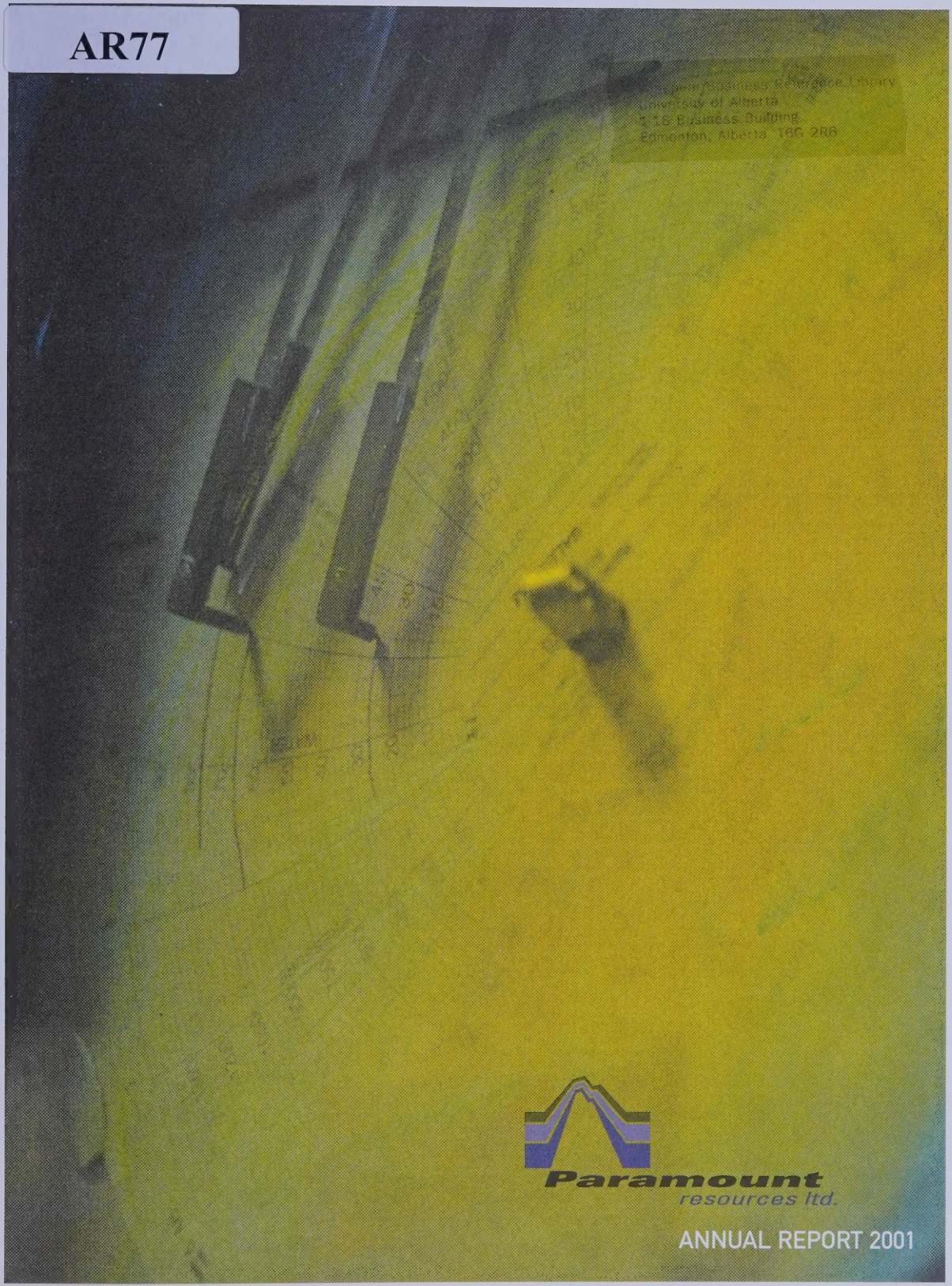
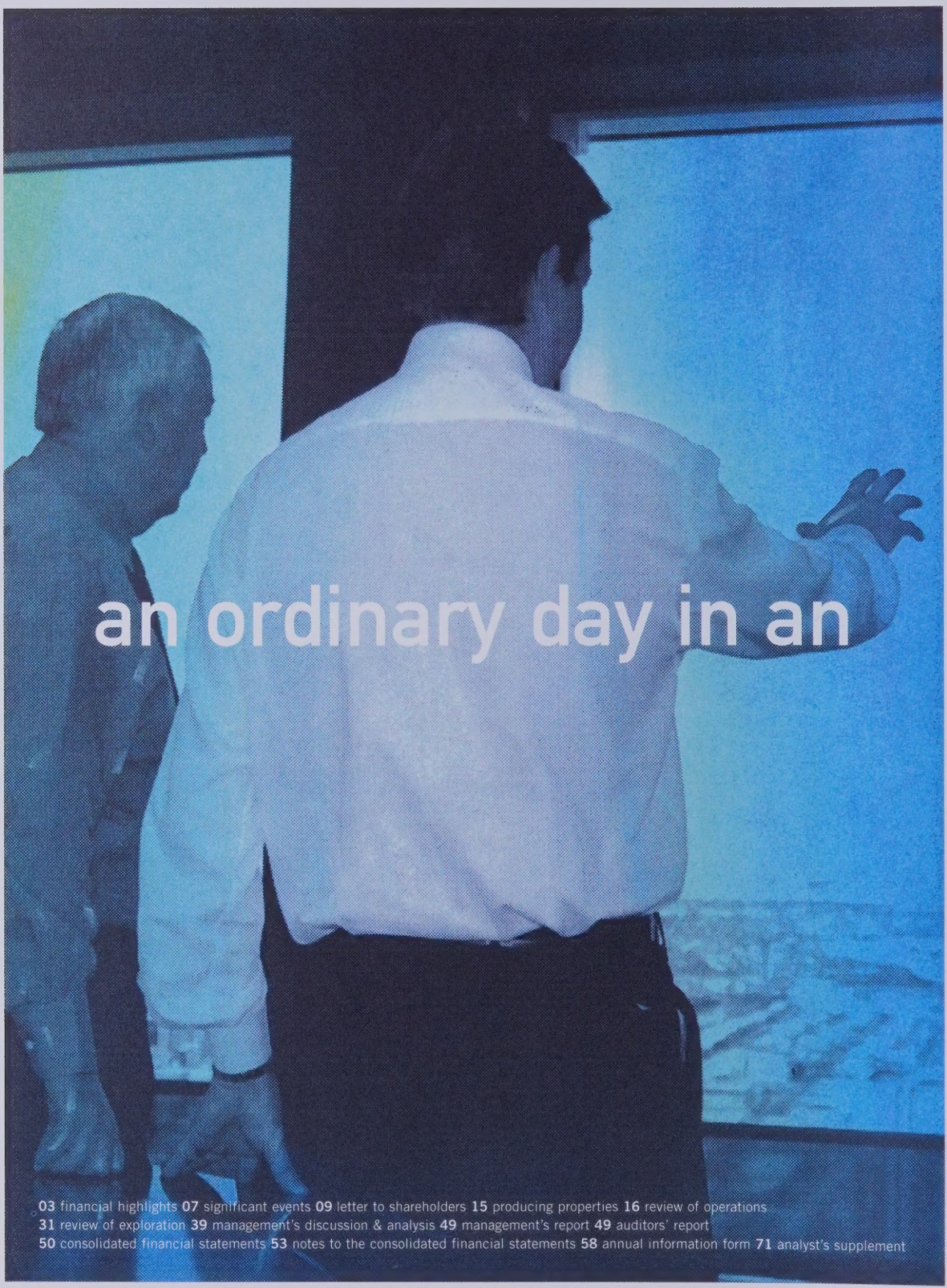
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Business & Energy Library
University of Alberta
3-16 Business Building
Edmonton, Alberta T6G 2R6



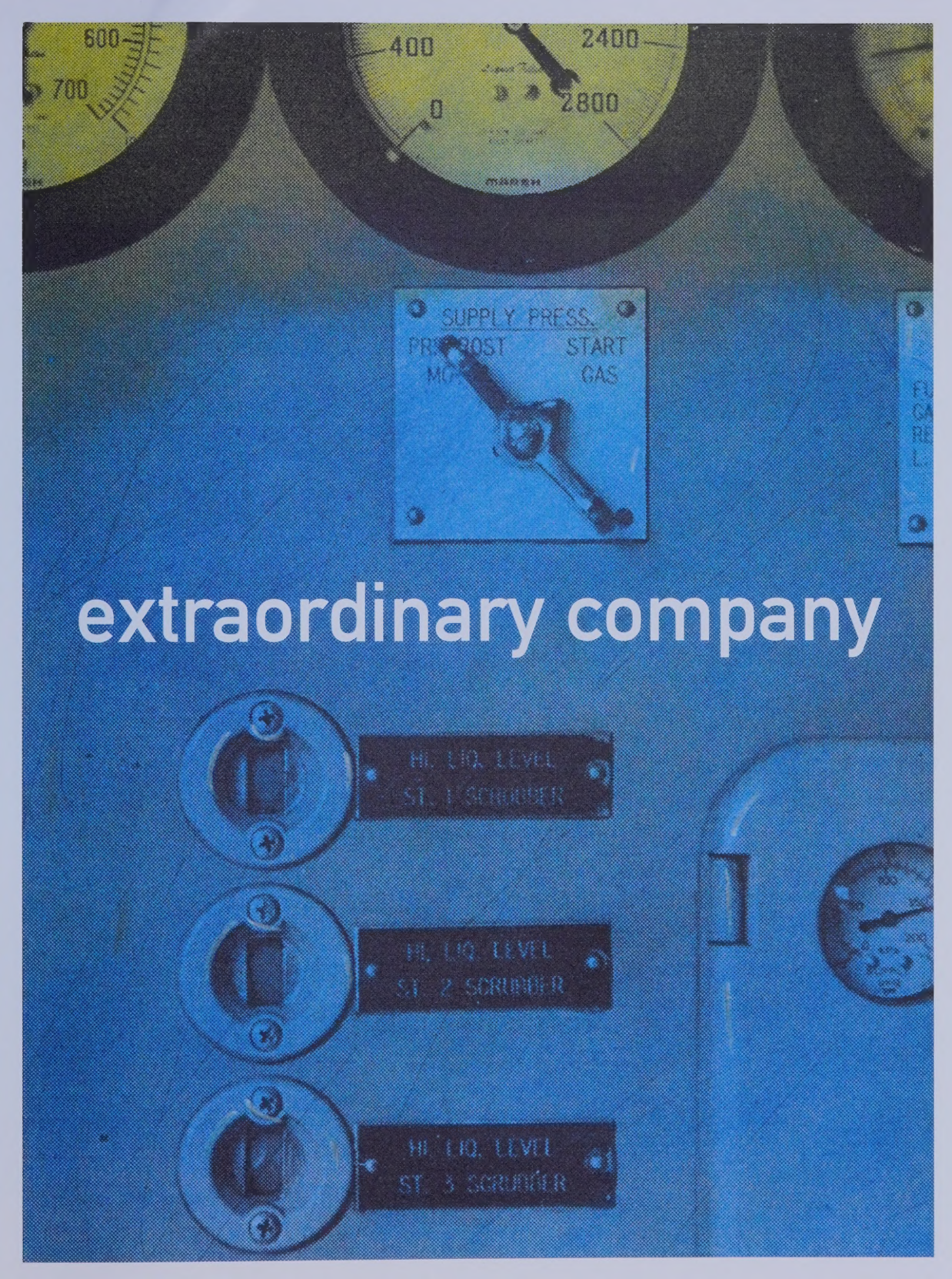
Paramount resources ltd.

ANNUAL REPORT 2001



an ordinary day in an

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SUPPLY PRESS.
START
GAS
extraordinary company

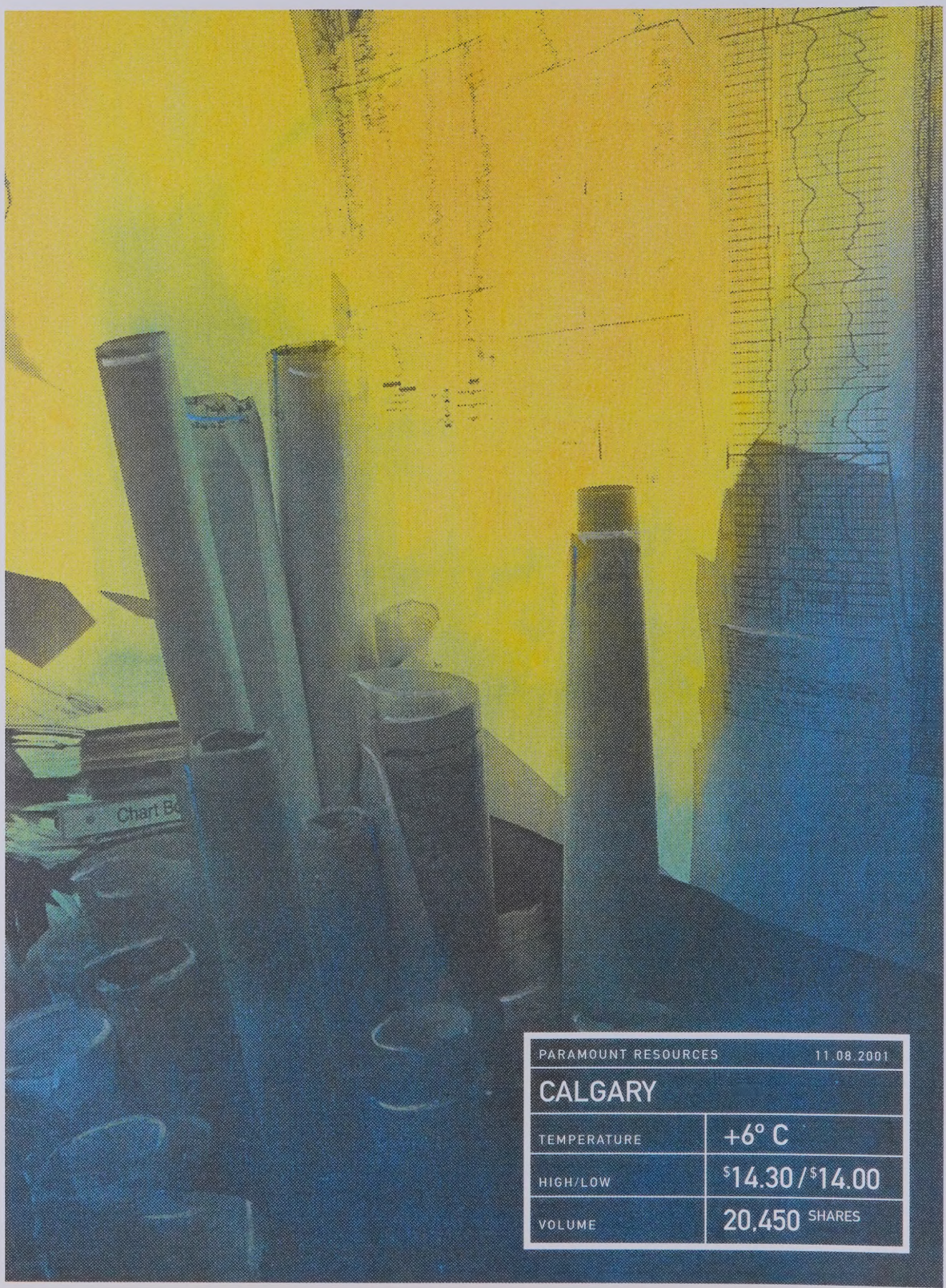


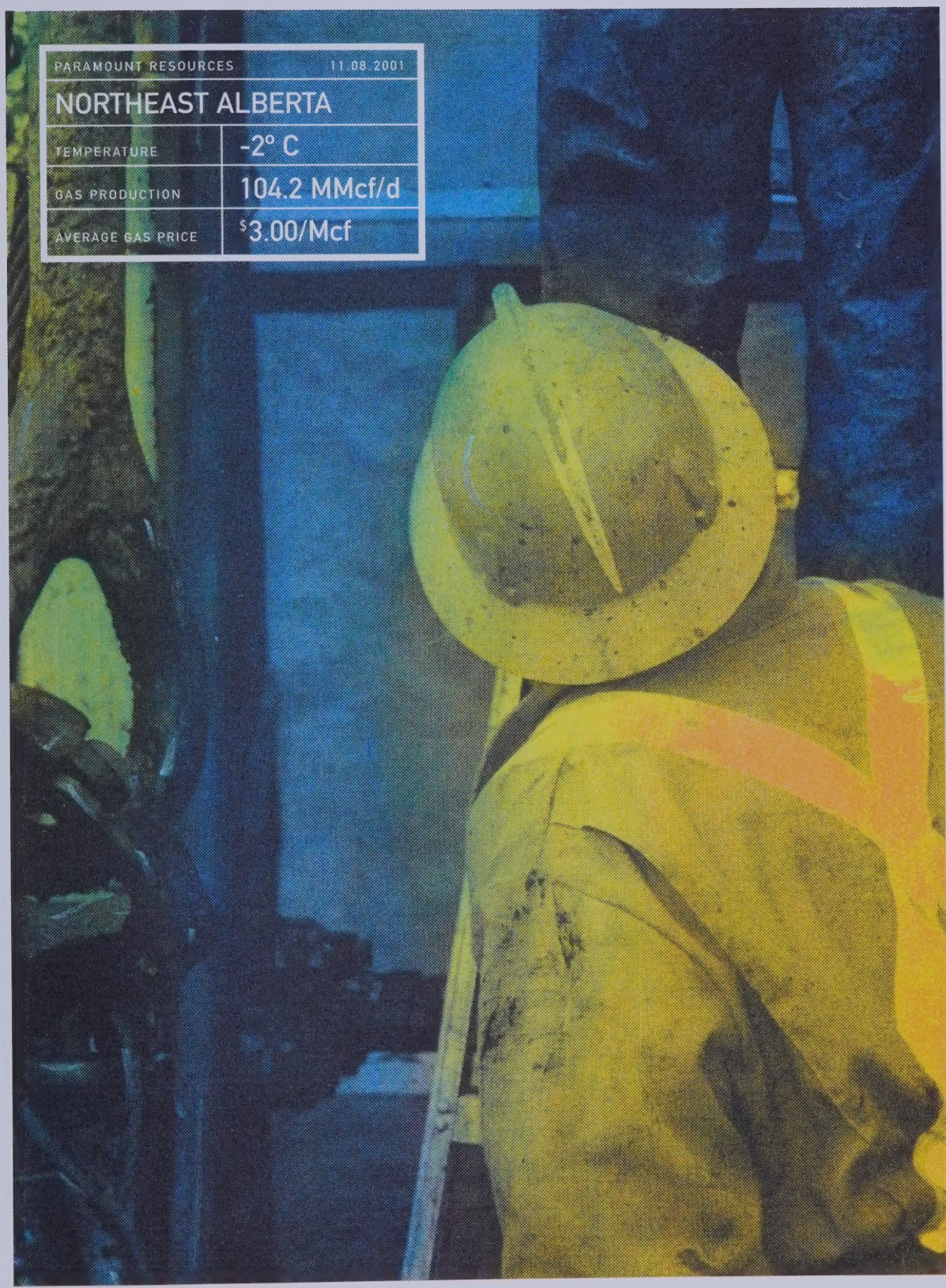
Paramount Resources Ltd. is a Canadian energy company with 95 percent of its revenue derived from natural gas sales. The Company explores for, develops, processes, transports and markets petroleum and natural gas. From its inception in 1978, the Company spent its first 15 years concentrating on the full cycle exploration and development of high deliverability shallow gas in northeastern Alberta. Through successful exploration, Paramount diversified from this traditional area of focus, adding new core areas in Central Alberta, Northwest Alberta, and the Liard Basin in Northeast British Columbia and the southern Northwest Territories. Paramount is continuing to spearhead the resurgence of exploration north of the 60th parallel in the Northwest Territories. Throughout its history, Paramount has successfully adapted to a myriad of operating climates to record sustainable growth per share in production, cash flow, earnings, and asset value.

FINANCIAL HIGHLIGHTS

(millions of dollars except per share amounts)	2001	2000	% change
FINANCIAL			
Gross Revenue	$ 528.4	$ 391.5	35
Cash Flow			
From operations	303.9	223.4	36
Per share (basic and diluted)	5.11	3.76	36
Earnings			
Net income	118.9	86.1	38
Per share (basic and diluted)	2.00	1.45	38
Capital Expenditures			
Exploration and development	252.7	218.5	16
Acquisitions (net of dispositions)	7.3	27.3	(73)
Other	1.2	3.2	(63)
Net capital expenditures	261.2	249.0	5
Total Assets	1,178.1	1,047.8	12
Long-term Debt (net of working capital)	288.9	292.4	(1)
Shareholders' Equity	537.2	418.3	28
Weighted Average Common Shares Outstanding (000s)	59,453.6	59,453.6	–
Common Shares Outstanding at Year End (000s)	59,453.6	59,453.6	–
OPERATING			
Production			
Natural gas (MMcf/d)	225.0	220.0	2
Crude oil and liquids (Bbl/d)	2,165	1,571	38
Average Prices			
Natural gas ($/Mcf)	$ 6.12	$ 4.59	33
Crude oil and liquids ($/Bbl)	$ 35.48	$ 37.80	(6)
Reserves (proved and probable)			
Natural gas reserves (Bcf)	564	657.4	(14)
Crude oil and liquids reserves (MBbl)	7,967	5,980	33
Total reserves[1] (Bcf)	643.7	717.2	(10)
Land (thousands of acres)			
Total net land holdings	4,984	4,648	7
Net undeveloped land holdings	3,765	3,597	5
Drilling Activity (gross)			
Gas	167	125	34
Oil	12	11	9
Other	1	2	(50)
D&A	16	25	(36)
Total wells	196	163	20
Success rate	92%	85%	8

(1) Throughout this report, unless otherwise stated, crude oil and liquids volumes have been converted to natural gas (Mcfeq) on the basis that one barrel of oil equals 10 Mcf of gas


Chart B
PARAMOUNT RESOURCES
11.08.2001
CALGARY
TEMPERATURE
+6° C
HIGH/LOW
$14.30 / $14.00
VOLUME
20,450 SHARES


PARAMOUNT RESOURCES
11.08.2001
NORTHEAST ALBERTA
TEMPERATURE
-2° C
GAS PRODUCTION
104.2 MMcf/d
AVERAGE GAS PRICE
$3.00/Mcf

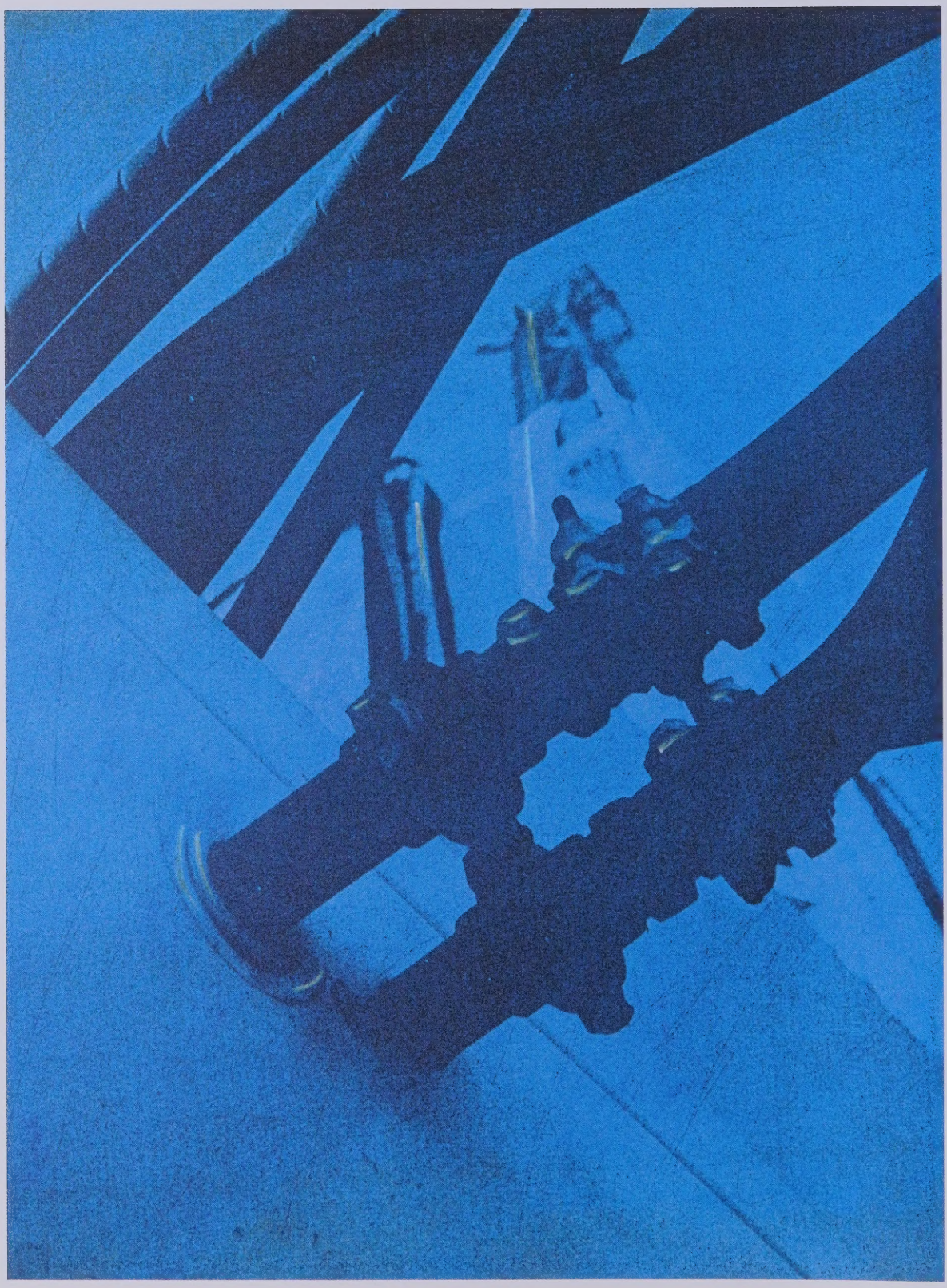

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SIGNIFICANT EVENTS: 2001

- Crude oil and natural gas revenue net of royalties increased 38 percent to $428.7 million.
- Funds provided by operations increased 36 percent to $303.9 million.
- Average natural gas, crude oil and natural gas liquid sales increased to a record 225 MMcf/d and 2,165 Bbl/d.
- Paramount closes the Kaybob North sour gas plant acquisition adding approximately 12 MMcf/d and 400 Bbl/d; establishing a majority interest and operatorship in the gas plant.
- Exploration agreement with the Behdzi Ahda First Nation in the Colville Lake Area of the Central Mackenzie Valley, Northwest Territories signed adding 148,000 acres of undeveloped land.
- Drilled the N-01 discovery well at Liard, NWT. Regulatory approval to produce the Mattson M-3 zone came August 17, 2001. The N-01 well added initial gross production rates of 13 MMcf/d (33% W.I.).
- Successfully acquired Exploration License EL 414 adding 209,654 acres of additional undeveloped land to the greater Colville Lake, Northwest Territories exploration area.
- Paramount Clover gas plant in Central Alberta Core area commissioned in October, 2001 adding 8 MMcf/d of productive capacity.
- A record 196 gross (158.7 net) wells drilled with a gross 92 percent success rate.

SIGNIFICANT EVENTS: JANUARY 2002 TO MARCH 2002

- Surmont compensation determined as at February 27, 2002. Paramount and the Surmont Producers Group disclose agreement with the Province of Alberta and Conoco, which provides, most importantly, for a royalty reduction of approximately $85 million plus interest effective January 1, 2001. Paramount will be entitled to approximately half of this compensation.
- Paramount successfully drills the shallowest horizontal well on record in Alberta at 100.8 meters true vertical depth.
- Cameron Hills final regulatory approval received allowing Paramount to tie in its Cameron Hills project adding 20 MMcf/d (18 MMcf/d net) of initial deliverability.
- Production begins at Cameron Hills on March 29, 2002.
- First quarter drilling in 2002 results in 109 wells (87.9 net) drilled with a 91 percent gross success rate.
- Drilled new discovery well at Maxhamish in northeastern British Columbia; tied in and on production March, 2002.



LETTER TO SHAREHOLDERS

On behalf of the Board of Directors, Officers, and Employees of Paramount Resources Ltd., it is my pleasure to present the 2001 Annual Report to Shareholders. Paramount is indeed alive and well, surviving in a Canadian energy industry that is undergoing dramatic consolidation as well as enduring considerable volatility in commodity prices. Many of the companies we have grown with and done business with in our industry have been consolidated into larger entities or outright sold, predominantly to U.S.-based companies. Natural gas prices in Alberta decreased through the year, dropping 81 percent from January 2001, to a yearly low in October, 2001 of Cdn. $2.50/gigajoule ("GJ"), putting considerable pressure on companies, particularly ones leveraged to natural gas such as Paramount.

In November and December 2000, the Canadian supply basin and the major consuming regions of North America saw temperatures plunge and gas supply was strained. Spot-market prices steadily rose to peak at Cdn. $12.91/GJ in January, 2001 as fears surfaced regarding inadequate storage supplies. A record completion of natural gas wells resulted; as well, additional energy was left in the gas supply as straddle operations reduced natural gas liquids extraction to boost supply. Meanwhile, demand abated as higher than seasonal temperatures were seen through the rest of the winter and demand was replaced by fuel switching or all out shut-in of plants and factories. This did in fact result in exceptionally low year-end storage levels; but also a changed relationship with considerably higher supply coupled with demand erosion had evolved. Storage levels were replenished at a rate unparalleled in previous years and the gauge read full in advance of the winter season. Through this period, prices plunged as producers were faced with the realization that there was more supply than demand and storage would be full; where would we put the gas? The events of September 11, 2001 left North America on the brink of recession and our industry facing the prospect of continued demand erosion for the industrial sector. The situation was further pressured when winter failed to arrive and one of the mildest November through January periods on record was experienced. In response to the dramatically lower prices, capital programs for natural gas have been slashed, changing again the supply expectations. North America seems to have left the prospects of recession behind and is anticipating renewed demand for energy commodities. The North American gas industry has had a test of its productive capacity and the results indicate that there is no longer a deliverability surplus. Natural gas supply has proven to be both reliable and dynamic. While no customers went short of gas in the winter of 2001, prices spiked indicating just how close the relationship of supply and demand is. The large surpluses of cheap natural gas are a thing of the past. While there are more than ample supplies that can and will be developed, consumers will have to support this development with higher prices. This scenario is reflected in the results of Paramount over the last few years as finding and development costs have increased and productive capacity of individual wells has decreased...but with improved pricing, the investment return of Paramount's projects are being maintained. Paramount looks forward to continued sharing in the development of the resources to help supply the North American natural gas market. We are well positioned with existing supply, a good, large undeveloped land inventory and, above all, the technical expertise particularly focused on the developing frontiers of North America.

FINANCIAL

Financial results for the Company were all records with revenue increasing 35 percent to $528.4 million, cash flow increasing 36 percent to $303.9 million, and earnings increasing 38 percent to $118.9 million. Paramount actively managed its price exposure starting in late 2000 and is continuing to do so today. Net hedging gains in 2001 were $15.8 million and as of March 2002, Paramount has crystallized approximately $40 million of incremental revenue as a result of hedging activities to be realized throughout 2002. Paramount's hedging position at the current time is 70 MMcf/d hedged at Cdn. $4.50/Mcf through to December 2002, and 30 MMcf/d hedged at US $2.92/Mcf from April to October 2002.

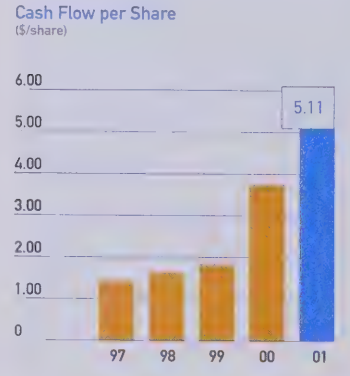
EXPLORATION AND DEVELOPMENT

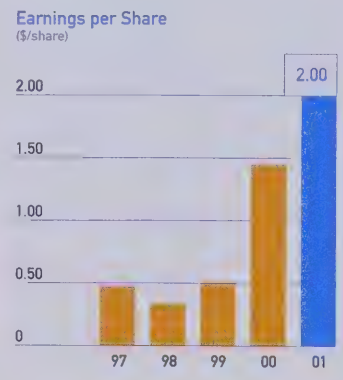
Paramount was successful in 2001 in increasing its overall daily production while at the same time spending less capital than cash flow. This strategy has resulted in a stronger balance sheet and therefore a stronger Paramount that is able to pursue opportunities aggressively in the near future in what has become a relatively attractive investment environment. Overall, production increased to a record 225 MMcf/d and 2,165 Bbl/d average throughout 2001. Production in Northeast Alberta was 109 MMcf/d; Central Alberta was 68 MMcf/d and 1,833 Bbl/d; Northwest Alberta produced 29 MMcf/d; Liard produced 9 MMcf/d; and the remaining was produced from other properties.

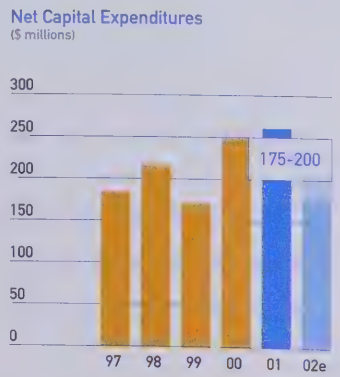
Capital expenditures were $128 million on exploration and development drilling; $95 million on production facilities; $11 million on geological and geophysical; $39 million on land; and $7 million on acquisitions net of dispositions. Drilling activity included 196 wells (158.7 net) drilled resulting in 167 gas wells (137.0 net), 12 oil wells (10.3 net), 16 dry holes (10.9 net) and 1 service well (0.5 net) for a gross success rate of 92 percent (93 percent net). Year-end proved plus probable reserves were 564 Bcf of natural gas and 8.0 million barrels of crude oil and natural gas liquids of which 438 Bcf and 6.3 million barrels were proved. Reserve additions of 46 Bcf of natural gas and 2.54 million barrels of crude oil and natural gas liquids resulted from new exploration, development, and acquisitions; production was 82 Bcf, and 0.75 million barrels; revisions were a negative 58 Bcf of gas reserves and a positive 0.2 million barrels of oil and natural gas liquids reserves. Paramount's undeveloped land inventory at December 31, 2001, stood at 3.8 million acres (net) and was independently valued at $100.9 million. Paramount has adopted a reserves subcommittee of the Company's Audit Committee that has reviewed the process and findings of the Company's independent engineers, McDaniel and Associates Consultants Ltd.

Looking forward to 2002, Paramount is finishing an active winter drilling season that will spend the majority of the Company's budgeted $175 – $200 million capital program. The Northeast Alberta Core Area has assumed the role of a cash generator for funding exploration and development activities in other parts of the Company. Capital expenditures of approximately $25 million reflect a small fraction of the cash flow that will be generated from this mature producing area. Despite this minimal spending, Paramount has been successful in making two New Field Wildcat discoveries, both of which will be evaluated to commence production potentially in 2003. Also in Northeast Alberta, Paramount has acquired over 100 sections in four distinct project areas of highly prospective oil sands leases with the expectation that these could be exploited using advanced thermal recovery processes such as SAG-D (Steam Assisted Gravity Drainage) and developed over the next decade. In Central Alberta, capital expenditures of approximately $70 million will be spent to drill, complete, and tie in 40 wells and this activity is anticipated to replace declines as well as grow the area by 25 MMcf/d and 1,000 Bbl/d. Northwest Alberta will see spending of approximately $50 million. Paramount was successful in obtaining approval from the National Energy Board to tie in its Cameron Hills project across the Northwest Territories/Alberta border to Paramount's Bistcho Lake sour gas plant and ultimately to the TransCanada pipeline system. Paramount spent over 18 months working to obtain the necessary approvals issued in February 2002. Field work was completed and initial production of 20 MMcf/d (18 MMcf/d net) came onstream March 29, 2002. The Liard core area has already met with initial success pursuing its Mattson sand play. Paramount is drilling two new wells and completing an existing third well, two of which should be producing by April 2002.

Paramount is testing a number of its exciting exploration prospects during the current drilling program to evaluate some of the higher risk / higher reward plays. At Bovie Lake, Paramount has drilled two approximately 3,200 meter Devonian tests. Both the J-76 and F-66 wells have been cased to total depth and are currently being completed. We have deferred drilling our initial exploration well in the Colville Lake area of the Northwest Territories due to rig availability. Paramount expects that it will be in a position to drill this well with advance planning in 2003. Paramount is nearing total depth on its New Field Wildcat at Pine Ridge in Wyoming. Intermediate casing has been set to approximately 16,000 feet and drilling and testing should be completed in April 2002. Results from three new wells are expected on the Company's East Lost Hills, California deep natural gas prospect in the second quarter. These results will allow us to fully evaluate the remaining potential of this play.







Paramount is also participating in the drilling of two deep Devonian prospects in Northeast B.C. which have significant potential for the Company.

GAS / BITUMEN CONCURRENT PRODUCTION

On February 27, 2002, Paramount and the Surmont Producers Group negotiated a Memorandum of Agreement ("MOA") with Conoco (formerly Gulf Canada Resources) and the Province of Alberta which provided for $85 million in the form of reduced royalties as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty on the Surmont lands as compensation related to the shut-in of gas on May 1, 2000 in the Surmont Area. Paramount is entitled to slightly over half this amount plus interest effective January 1, 2001. The MOA also provides an incentive to all three parties for finding and implementing a technical solution to minimize the effects of concurrent production of the natural gas reserves at Surmont or means to repressure the reservoirs so as not to negatively effect the ultimate economic recovery of the bitumen resource.

CORPORATE INVESTMENTS

Paramount started in late 1999 to achieve further diversification of its asset base by investing in other corporate entities, be it public or private, to gain exposure to opportunities which others are focused on pursuing without further burdening Paramount's infrastructure. Paramount has been highly successful in growing these investments from less than $3 million of start-up capital to over $50 million. Paramount to date has investments in three public companies and four private companies, the most significant of which are Peyto Exploration and Development Corp., Spearhead Resources, and Triquest Exploration, which are public exploration and development companies, as well as Wilson Drilling which is a private drilling contractor.

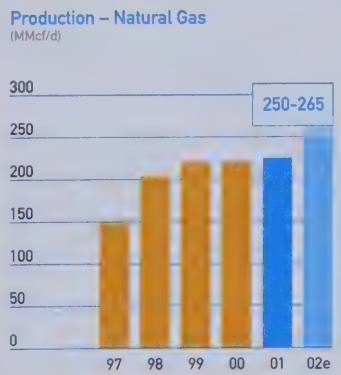
OUTLOOK

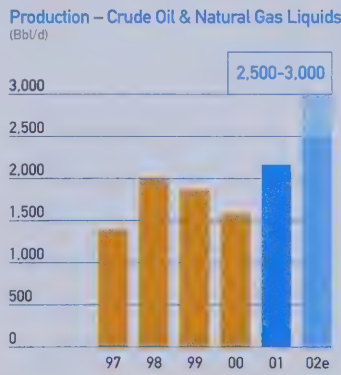
Looking ahead at the remainder of 2002, the prospects for a prosperous year look good. Natural gas prices have recently strengthened, sooner than most had anticipated and just in time to enhance the value of new production added by Paramount's winter drilling season. Paramount anticipates growing its production while at the same time keeping capital spending within cash flow. Paramount's financial position should continue to improve and the Company will continue to monitor the market for significant opportunities at more reasonable prices than in 2001. Clearly, Paramount has positioned itself with a large inventory of high impact exploration supported by a stable and diversified production base. Paramount looks to continue to return value to its shareholders through the remainder of 2002 and into the future.



C.H. Riddell
President and Chairman of the Board
April 5, 2002



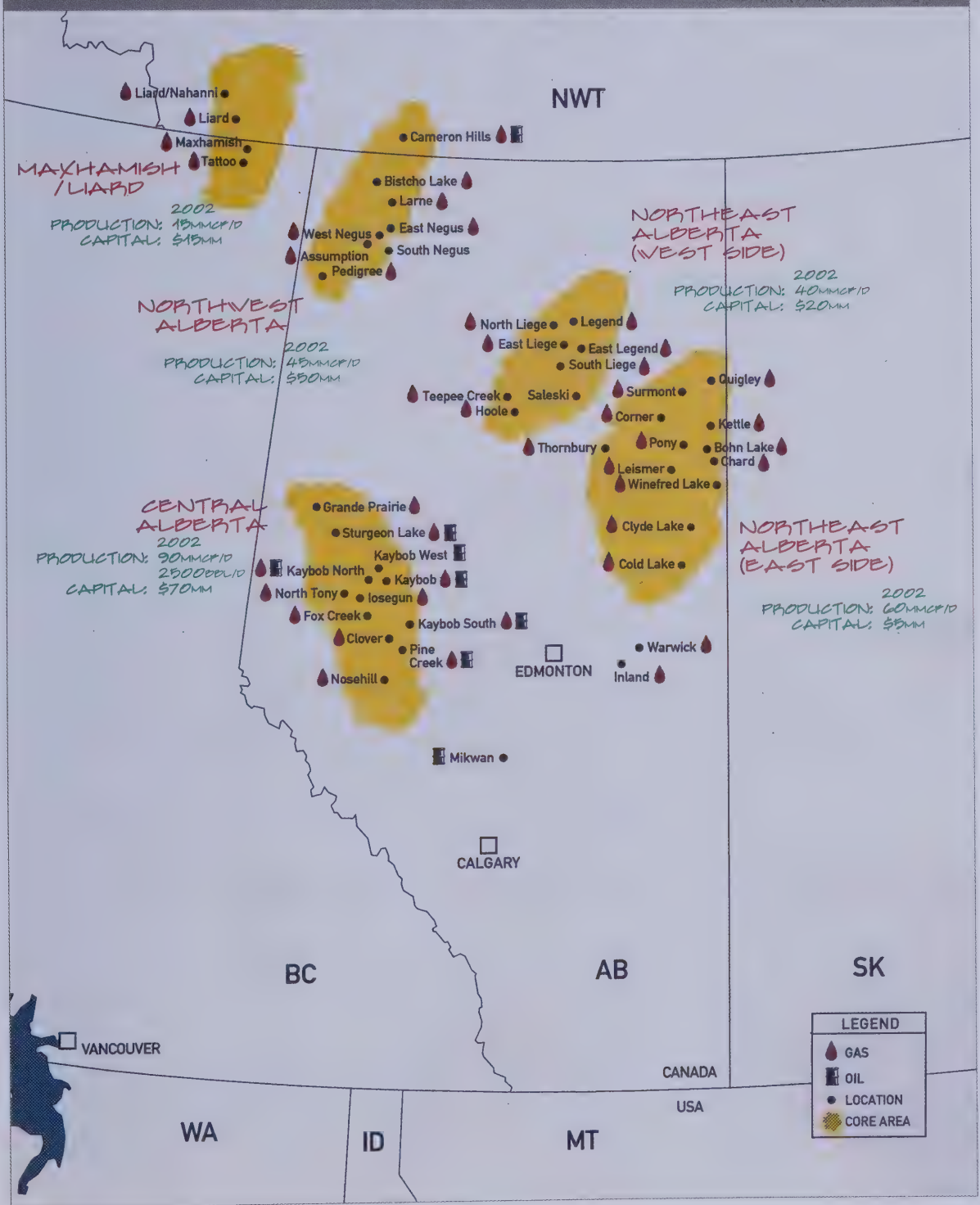





PARAMOUNT RESOURCES
11 08 2001
CALGARY
TEMPERATURE
+6° C
HIGH/LOW
$14.30/$14.00
VOLUME
20,450 SHARES


PARAMOUNT RESOURCES
11.10.2001
CENTRAL ALBERTA
TEMPERATURE
0° C
GAS PRODUCTION
80.9 MMcf/d
AVERAGE GAS PRICE
$3.00/Mcf

PRODUCING PROPERTIES



PARAMOUNT IN REVIEW

Paramount's commitment to its shareholders is to add value. Paramount has identified a strategy for growth that revolves around an entrepreneurial spirit wherein we grow the smaller, more manageable pieces using our proven successful formula and the sum of the parts add to total corporate growth. The Company has equipped its five core areas with distinct operating staff, capital budgets and targets as well as shared services such as drilling, facilities and construction, accounting, land administration and corporate compliance. A pure exploration group with unique play concepts outside of the defined core operating areas provides discoveries that will evolve into future core growth areas for the Company.

NORTHEAST ALBERTA CORE AREA

Paramount's original Northeast Alberta Core Areas have grown to mature production areas. They are characterized by steady, low decline production that generates far more cash flow than is reinvested as capital expenditures. Opportunities for value creation are still being pursued with the goal to maintain production or at least mitigate declines as much as possible. There still remains a significant suite of opportunities to pursue although the Alberta Energy and Utilities Board's position with respect to gas exploration that is in conflict with bitumen has made many of these relatively unattractive to pursue. Paramount was, despite this low reinvestment level, successful in making two New Field Wildcat discoveries, potentially providing new production areas by as early as next year.

The Northeast Alberta Core Areas were responsible for approximately 17 percent of Paramount's 2001 capital expenditures and drilling of 22 percent of the Company's total wells. With the limited capital program, reserves were relatively unchanged except for negative revisions at East Legend and the non-operated Teepee Creek field associated with poorer than anticipated well performance in these two areas.

Paramount has managed to gain considerable knowledge with respect to the bitumen resource in Northeast Alberta and the application of Steam Assisted Gravity Drainage (SAGD) as a recovery method. Four new lease areas comprising over 100 sections of land have been assembled in the Surmont, Christina Lake, Leismer and Corner areas. A future focal point for this core area will be pursuing the development of these bitumen prospects employing SAGD technology. A number of similar projects are in varying stages of piloting and commercial production in the general vicinity of Paramount lands, and the Company will benefit from this information as it moves its own projects forward.

CENTRAL ALBERTA CORE AREA

In Central Alberta, the Company's most significant region of growth in the past five years, Paramount continues to pursue strategic land and infrastructure acquisitions to optimize value from this core area. Opportunities in Central Alberta range in depth from 1,500 metres to over 4,000 metres targeting from Cretaceous-aged reservoirs to older Devonian strata, so one can imagine this provides for a larger variance in the costs as well as recoverable reserves for individual wells.

The Central Alberta Core Area was exclusively responsible for the 38 percent year-over-year increase in the Company's total oil and natural gas liquids production. Gas production increased to 68.4 MMcf/d from 63.7 MMcf/d in 2000. Paramount has put significant effort into gaining more control of its operations in this area in order for it to maximize its onstream time and minimize its per unit operating costs.

Approximately 30 percent of the capital expenditures in Central Alberta were focused on facilities projects, which included tie ins at Kaybob, Kaybob North, Pine Creek, North Tony and Kaybob West as well as the construction of compression facilities at Pine Creek and Clover and upgrades to the oil battery at Kaybob West. The remaining capital was spent on drilling and completion activities and land acquisitions.

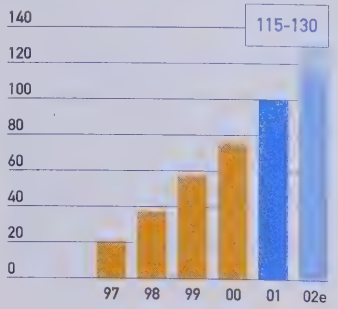
Production – North Alberta (West Side)
(MMcf/d)



Production – North Alberta (East Side)
(MMcf/d)



Production – Central Alberta
(MMcfeq/d)



NORTHWEST ALBERTA CORE AREA

Northwest Alberta has evolved into three sub-regions with distinct play types. The Bistcho/ Cameron Hills trend north of Zama is currently making its metamorphosis to the infrastructure network visualized by the Company nearly ten years ago. As threshold reserves, existing infrastructure, gas prices, regulatory requirements and community involvement have finally come together, Paramount is currently in the process of pipelining to bring the Northwest Territories gas reserves discovered at Cameron Hills in the late 1980s onstream.

Production increases in Northwest Alberta in 2001 came as a result of the development of the Charm Elkton pool at Pedigree; the discovery and tie in of the Shetland Shunda pool; and the discovery, development and tie in of additional Gething and Bluesky gas at Negus West, two small Pleistocene pools at Negus East and successful Devonian Slave Point and Sulphur Point tests at Bistcho Lake and Larne.

The Northwest Alberta Core Area was responsible for 19 percent of Paramount's 2001 capital expenditures, drilling 37 percent of the Company's total wells. Over 144,500 acres of undeveloped land were added primarily as a result of successful Crown land purchases in the Negus East area. This brings the total to 627,537 acres accounting for 28 percent of Paramount's undeveloped land base. Negative reserve revisions at Cameron Hills offset reserve additions in other regions, leading to a 16 percent reduction in reserves in the Northwest Alberta Core Area. Reserves were decreased in the Cameron Hills project area as a result of unsuccessful testing of the Slave Point zone in three shut-in wells, and decreased recovery factors applied to the shut-in Sulphur Point reserves as a result of performance data from somewhat analogous pools at Bistcho. Additional wellbore remediation work is planned for two of the Slave Point potential gas wells in 2002. If successful, a portion of these reserves may be rebooked.

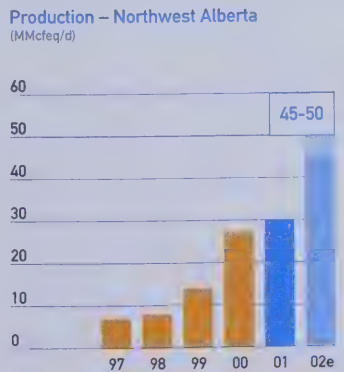
In 2002, plans are in place to spend $50 million in Northwest Alberta, over 25 percent of Paramount's total capital program. This includes the drilling of 48 wells, the acquisition of two large 2D seismic surveys at Bistcho Lake and Cameron Hills and a 3D seismic program at Cameron Hills, as well as the tie in of the significant shut-in gas reserves at Cameron Hills. A single-rig drilling program is also underway, focused on evaluating the future oil development potential in the Sulphur Point formation at Cameron Hills. Potentially, this oil development will occur in 2003.

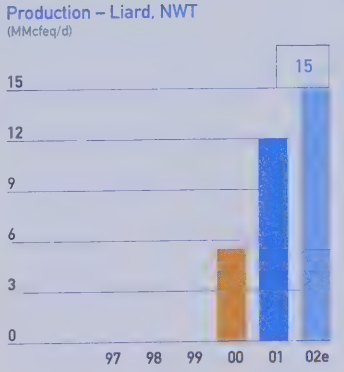
LIARD BASIN – NORTHEAST BRITISH COLUMBIA/NORTHWEST TERRITORIES CORE AREA

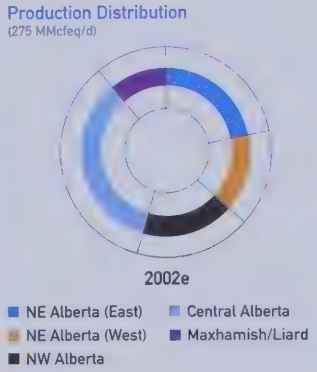
Liard, the Company's least mature core area, is still very much in its exploratory and early exploitation phase. With additional opportunities identified within the Mattson sand play and seismic acquisition taking place this winter targeting Devonian play concepts. Paramount is continuing to identify and pursue opportunities which will create value for our shareholders.

Production from the Liard Core Area increased 72 percent year over year, primarily as a result of exploration success along the Mississippian Mattson trend at N-01, which came onstream on August 17, 2001, and the discovery and development of the Tattoo pool in Northeast British Columbia. Capital expenditures in the Liard area were heavily weighted to facilities, with the construction of the Tattoo plant and the tie in of the N-01 and O-35 wells in the Northwest Territories. Reserve additions at N-01, Tattoo and the non-operated Devonian trend at F-25A were offset by negative reserve revisions in the Mississippian Mattson pool at F-36.

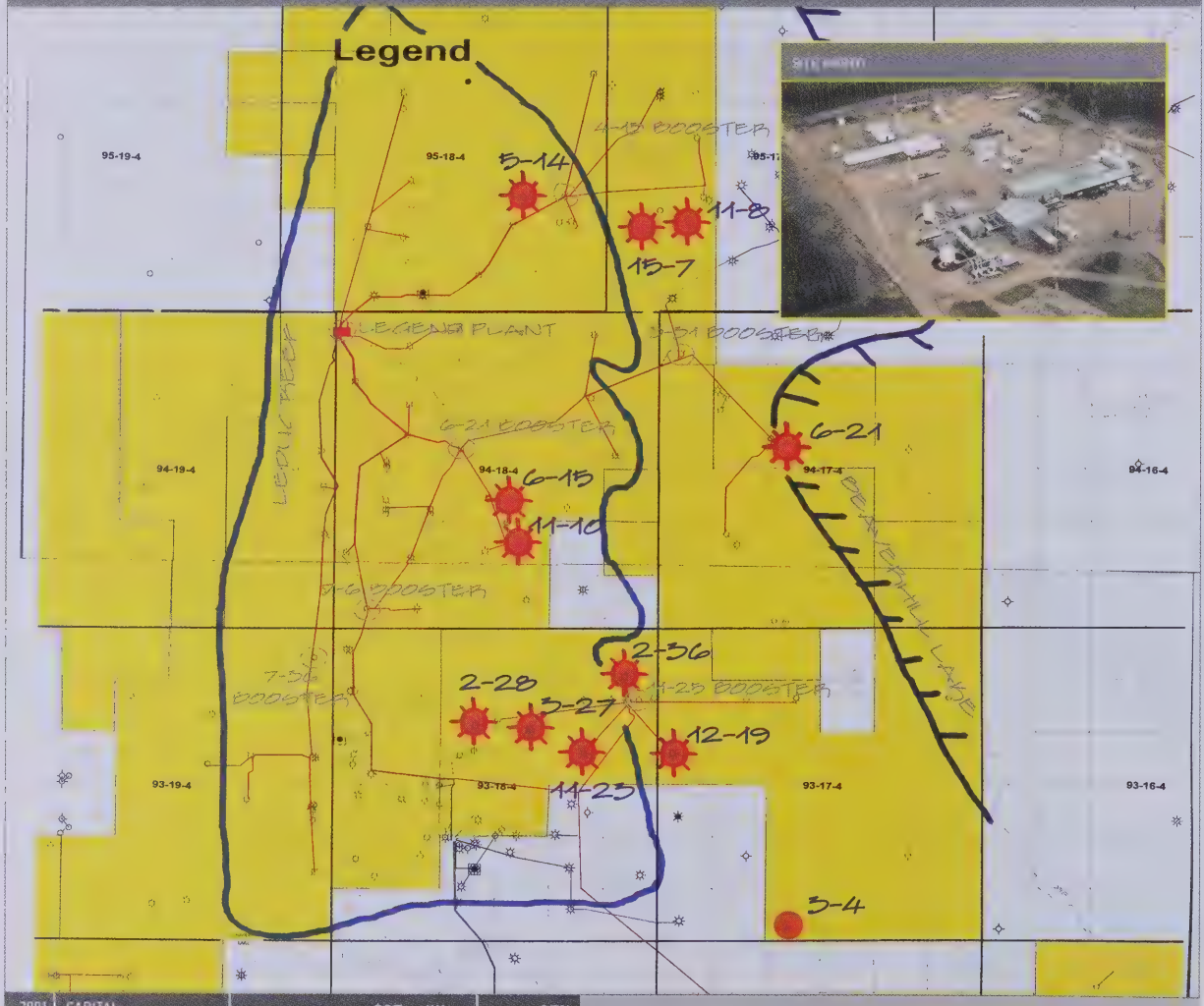
Three rigs will be active in the Liard area in early 2002. A total of five locations will be drilled along with the completion of three existing wells. Two exploratory locations will be drilled at Bovie Lake in the Northwest Territories and have Devonian targets. The other three locations are targeting shallower Mississippian zones at Maxhamish and south of Tattoo. Winter 2002 seismic activity includes two 3D seismic programs located west and south of the Liard K-29 Devonian pool and a third 3D program located at Arrowhead.







NORTHEAST ALBERTA (West Side)

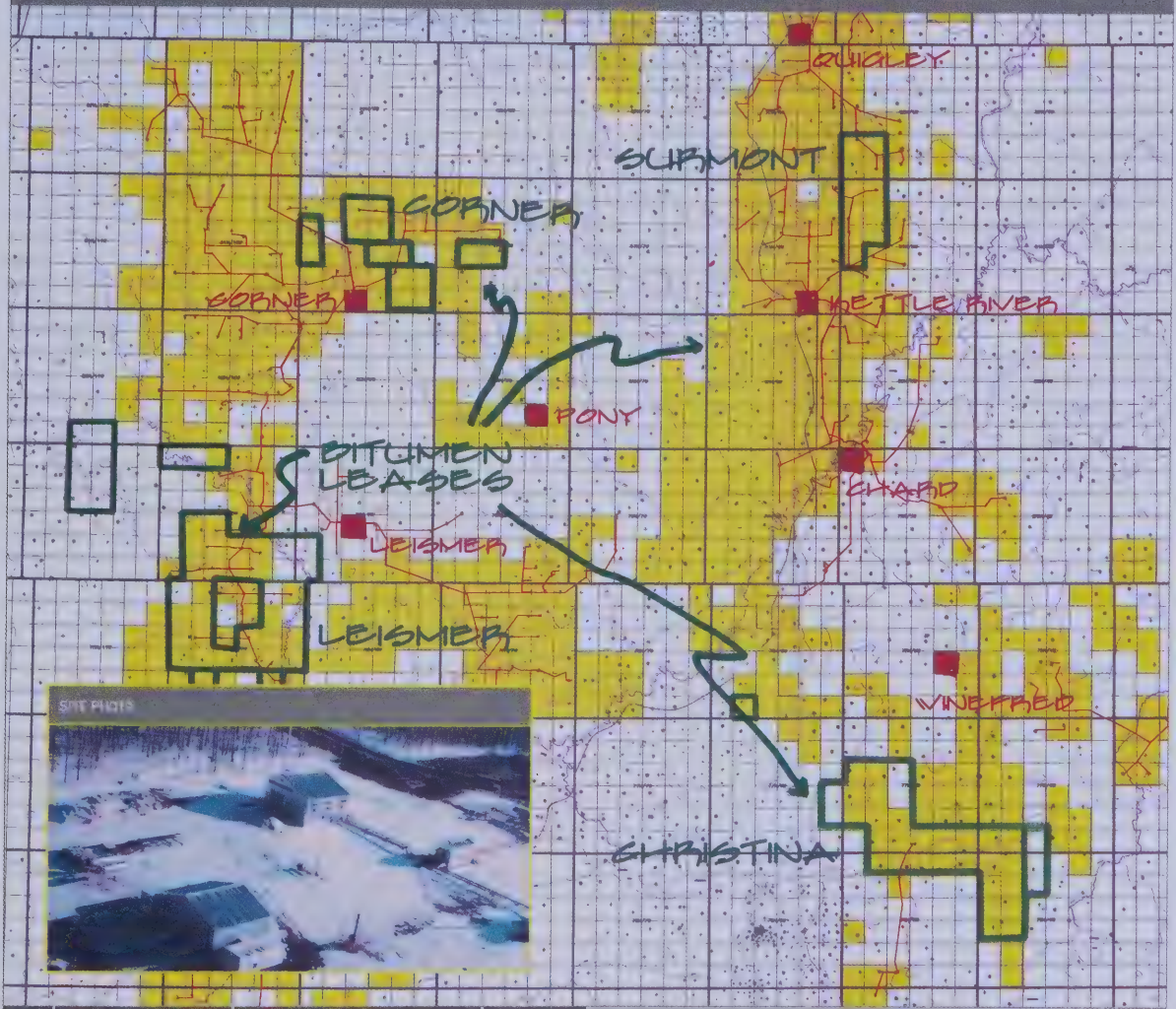


2001	CAPITAL	$27 million	35%
	DRILLING SUMMARY	20 gross (17.3 net) wells	42%
	PRODUCTION	41.6 MMcf/d	(1%)
	RESERVES	104 Bcf	(22%)
	UNDEVELOPED LAND	351,913 acres	(28%)
	OPERATING COSTS	$0.75/Mcf	32%
2002	CAPITAL BUDGET	$20 million	(18%)
	PRODUCTION FORECAST	40 MMcf/d	(4%)

Paramount is targeting high permeability Cretaceous McMurray and Wabiskaw sands as well as Devonian Grosmont, Wabamun and Leduc carbonate subcrop plays in the Northeast Alberta West Side Core Area. Utilizing cutting-edge horizontal drilling technology and drilling practices, new wells are able to produce gas at rates much higher than traditional vertical wells. Paramount continues to exploit existing gas pools through development drilling while at the same time exploring for new gas pools. New Wabiskaw and McMurray gas pools (100% Paramount working interest) discovered with recent drilling will be fast tracked for development drilling and tie in in the upcoming 2002/2003 winter drilling season.

Paramount's strategy in this area is to maintain gas production volumes from existing properties and to explore continually for new reserves, especially where we can take advantage of existing infrastructure.

NORTHEAST ALBERTA (East Side)



SPE PHOTO

2001	CAPITAL	$20 million	17%
	DRILLING SUMMARY	24 gross (21.4 net) wells	(20%)
	PRODUCTION	67.1 MMcf/d	(13%)
	RESERVES	173 Bcf	(8%)
	UNDEVELOPED LAND	292,894 acres	10%
	OPERATING COSTS	$0.78/Mcf	-34%
2002	CAPITAL BUDGET	$5 million	(75%)
	PRODUCTION FORECAST	62 MMcf/d	(11%)

Natural gas is found in multiple targets within shallow (<500 metres) Cretaceous reservoirs. These targets include Grand Rapids, Clearwater, Wabiskaw and McMurray sandstones. Gas pools consist of fluvial channel and marine bar sands with a combination of both stratigraphic and structural traps. Pools are found using detailed mapping and extensive 2D seismic bright spot technology. Vast bitumen resources are also present, and are situated within McMurray channel sands at shallow depths. These bitumen sands are exploited using horizontal wells and steam, a process referred to as SAGD (Steam Assisted Gravity Drainage). Bitumen resources require extensive capital to exploit but provide long-term reserves (hundreds of millions of barrels). Paramount is closely monitoring the rapid advances of bitumen recovery and development technologies being applied by industry. This knowledge will dramatically improve the success of Paramount projects when they are, in fact, developed. In the meantime, Paramount has inventoried these projects for the future.

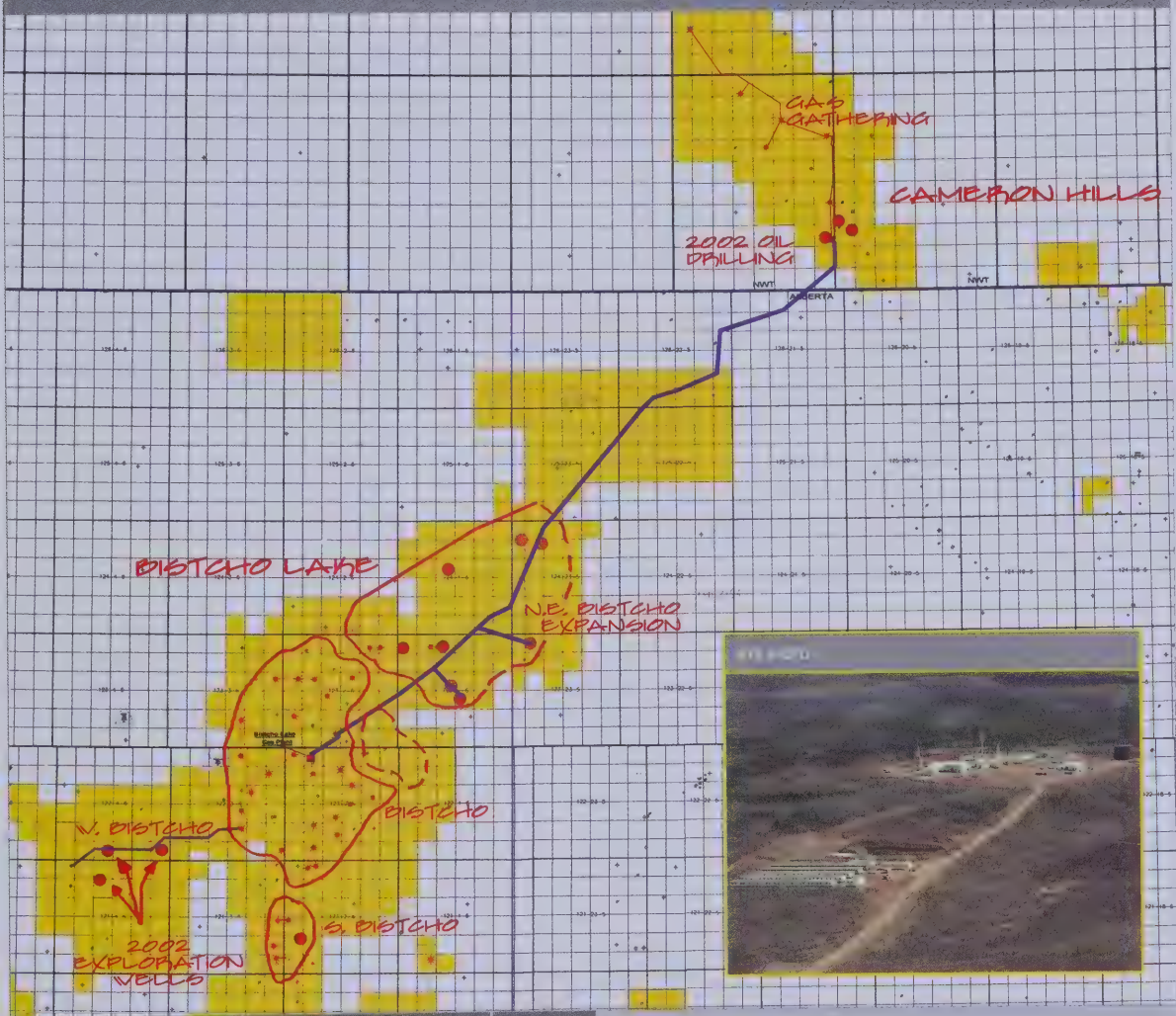
CENTRAL ALBERTA



2001	CAPITAL	$127 million	(131%)
	DRILLING SUMMARY	68 gross (56.7 net) wells	62%
	PRODUCTION	68.4 MMcf/d 1,833 Bbl/d	7% 66%
	RESERVES	140 Bcf 7.2 MMBbls	(10%) 42%
	UNDEVELOPED LAND	277,848 acres	(17%)
	OPERATING COSTS	$0.62/Mcfeq	15%
2002	CAPITAL BUDGET	$70 million	(26%)
	PRODUCTION FORECAST	115 to 130 MMcfeq/d	33-50%

The Central Alberta Region, situated near the town of Fox Creek, consists of properties that produce from Cretaceous, Triassic and Devonian formations. Paramount controls over 457,000 acres of land in this area and produced 68.4 MMcf/d and 1,833 Bbl/d in 2001, as opposed to 63.7 MMcf/d and 1,176 Bbl/d in 2000. Production is processed at 23 facilities, 10 of which are operated by Paramount. The majority of production in this area comes from Kaybob North (45%), Kaybob (27%) and Pine Creek (11%). The Company strives to gain operatorship and therefore control of all aspects of the operations to maximize production and minimize costs. 2001 featured new discoveries in Notikewin, Gething, and Triassic formations and the commissioning of a new gas plant in the Clover area. 2002 activity will see the drilling of 40 wells to develop these new discoveries, and will infill several other oil and gas pools in the region. This region affords year-round access, excellent infrastructure, and numerous high-quality, medium depth drilling targets.

NORTHWEST ALBERTA



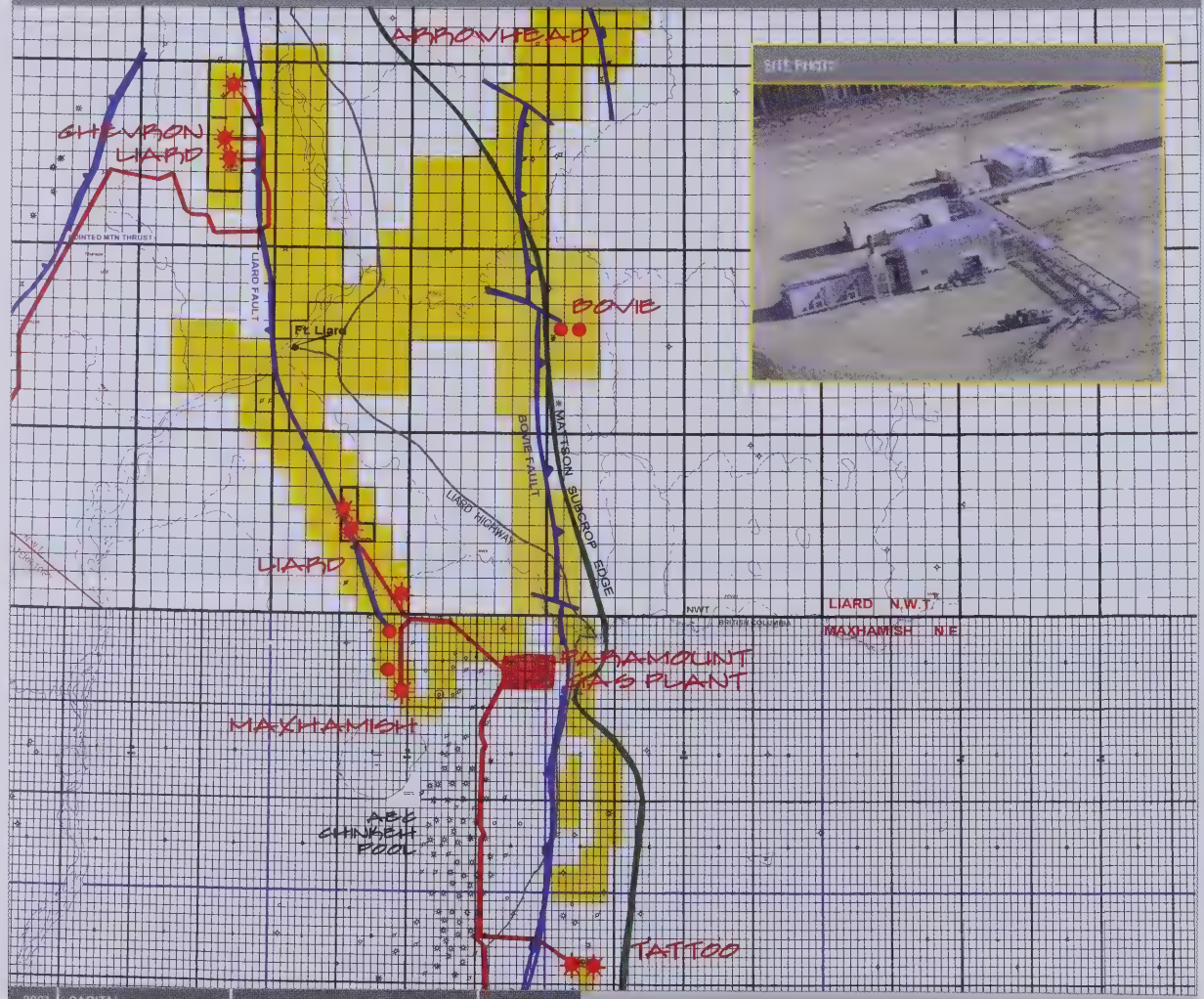
2001	CAPITAL	$50 million	25%
	DRILLING SUMMARY	73 gross (58.7 net) wells	22%
	PRODUCTION	29.4 MMcfeq/d	12%
	RESERVES	113 Bcf 0.6 MMBbls	(16%) 0%
	UNDEVELOPED LAND	627,537 acres	20%
	OPERATING COSTS	$0.54/Mcfeq	26%
2002	CAPITAL BUDGET	$50 million	0%
	PRODUCTION FORECAST	45 to 50 MMcfeq/d	56-70%

Situated in the extreme northwest corner of Alberta, gas exploration and development targets include the shallow sands and gravels of the Pleistocene and Cretaceous Bluesky/Gething sands at Negus and Assumption; in the Pedigree area, medium depth Mississippian carbonates at their subcrop edges and in the Larne, Bistcho Lake and Cameron Hills areas, slightly sour gas is recovered from multiple stratigraphic and structural traps in Middle Devonian carbonates. Light oil has also been recovered during production tests conducted at the Cameron Hills property.

In Northwest Alberta, Paramount has an extensive land and geophysical base to which significant additions were made in 2001 and the first quarter of 2002.

At Cameron Hills in the Northwest Territories, three Sulphur Point oil delineation wells were drilled and completed, and both a 2D and a 3D seismic survey were shot. Construction of gas gathering infrastructure and a trans-border pipeline from Cameron Hills to the Bistcho Lake gas processing facility were completed in first quarter 2002. Production commenced at Cameron Hills March 29, 2002.

LIARD, NWT



2001	CAPITAL	$20 million	0%
	DRILLING SUMMARY	5 gross (2.3 net) wells	150%
	PRODUCTION	9.6 MMcfeq/d	72%
	RESERVES	19.0 Bcf	(45%)
	UNDEVELOPED LAND	350,667 acres	64%
	OPERATING COSTS	$0.47/Mcfeq	81%
2002	CAPITAL BUDGET	$15 million	(25%)
	PRODUCTION FORECAST	15 MMcfeq/d	60%

Exploration and development activity in the Liard core area is focused on the relatively under-explored Mississippian and Devonian targets. Extensive 2D and 3D seismic data is utilized to delineate prospects along the Bovie and Liard fault trends. Existing operated production from gaswells at Tattoo, Maxhamish and Liard is from the Mississippian, while non-operated production at Chevron Liard is from the Devonian.

During 2001, successful Mississippian wells were tied in at Liard and Tattoo and the Devonian well at F-25A was tied in to the Chevron Liard facility. New seismic data was acquired at Bovie and Maxhamish as we continued to build our prospect inventory.

Activity during the first quarter of 2002 included the drilling of 5 locations and the acquisition of 3D seismic along the Liard and Bovie faults. Two Mississippian wells at Maxhamish are currently being tied in and two Devonian locations drilled at Bovie will be completed before spring breakup.

PRODUCTION

Paramount recorded 5 percent growth in total production in 2001, receiving revenue on 246.6 MMcfeq/d of sales as compared to 235.7 MMcfeq/d in 2000. Natural gas sales were up just over 2 percent to 225.0 MMcf/d, accounting for 91 percent of the Company's total production. Crude oil and natural gas liquids production increased 38 percent to 2,165 Bbl/d from 1,571 Bbl/d in 2000. Paramount continued to post year-over-year growth in each of its three growth-oriented core areas, with total production from Central Alberta, Northwest Alberta and Liard increasing 16 percent from 108.3 MMcfeq/d in 2000 to 125.7 MMcfeq/d in 2001. Paramount currently forecasts 2002 natural gas production to average 250 to 265 MMcf/d and liquids production to average 2,500 to 3000 Bbl/d.

Production (MMcfeq/d)	2002e	2001	2000
Northeast Alberta (East Side)	60	67.1	76.8
Northeast Alberta (West Side)	40	41.6	42.2
Central Alberta	115 – 130	86.7	75.5
Northwest Alberta	45 – 50	29.4	27.3
Liard	15	9.6	5.5
Other	–	12.3	8.4
Total	275 – 295	246.7	235.7

PROFITABILITY

Paramount's business philosophy dictates a strong and continual focus on economics and profitability. Every employee's mandate is to turn ideas into value for our shareholders. In combination with cost control, the result of this strategy is a history of positive earnings, and continued growth in earnings per share, while working predominantly within our internally-generated cash flow.

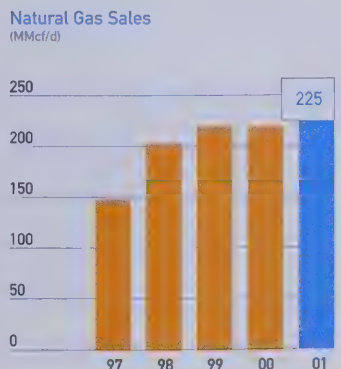
NATURAL GAS AND CRUDE OIL PRICES

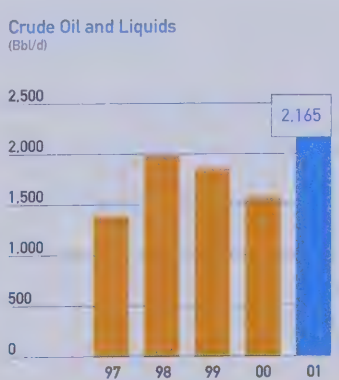
During 2002, Paramount's natural gas-focused strategy, positioned the Company to take advantage a very volatile natural gas market. Paramount realized an average natural gas sales price of $6.12/Mcf in 2001, an increase of 33 percent from $4.59/Mcf in 2000. Crude oil and liquids prices averaged $35.48/Bbl in 2001 compared to $37.80/Bbl in 2000.

Stronger natural gas demand and the Company's hedging initiatives in 2001 resulted in an increase of 151 percent in Paramount's average natural gas sales price. Included in the price is approximately $0.19/Mcf profit from natural gas commodity hedges which were in place during 2001. The hedges included 120 MMcf/d of natural gas at NYMEX at an average price to October 2001 of US $4.88/Mcf or $6.85/Mcf AECO after fixing the NYMEX/AECO basis on 100 MMcf/d.

REVENUE RECONCILIATION

Strong commodity prices translated into record financial results for Paramount in 2001. The Company recorded gross petroleum and natural gas sales revenue of $528.4 million, an increase of $136.9 million, or 35 percent, year over year. Gross revenue includes gains from commodity hedging activity of $15.8 million.







Cash flow increased $80.5 million, or 36 percent, to a record $303.9 million in 2001. Cash flow per share increased to $5.11, up 36 percent from $3.76 per share in 2000. Earnings totaled $118.9 million, a 38 percent increase from $86.1 million in 2000. Earnings per share increased 28 percent year over year to $2.00/share.

Cash Flow Reconciliation	2001		2000	
Volume (MMcfeq)[1]	90,027		86,270	
	($ million)	($/Mcfeq)	($ million)	($/Mcfeq)
Gross revenue[2]	$ 528.4	$ 5.87	$ 391.5	$ 4.54
Royalties (net of ARTC)	(99.7)	(1.11)	(80.6)	(0.93)
Operating costs	(61.1)	(0.68)	(48.0)	(0.56)
Netback	367.6	4.08	262.9	3.05
G&A	(12.4)	(0.14)	(9.7)	(0.11)
Interest on long-term debt	(19.3)	(0.21)	(22.3)	(0.26)
Lease rentals	(4.3)	(0.05)	(5.2)	(0.06)
Large Corporation/current taxes	(27.7)	(0.31)	(2.3)	(0.03)
Cash flow	$ 303.9	$ 3.37	$ 223.4	$ 2.59
Weighted average shares (millions)	59.5		59.5	
Cash flow per share	$ 5.11		$ 3.76	

(1) Barrels of oil converted to gas sales on the basis of 1 barrel = 10 Mcf
(2) Revenue includes petroleum and natural gas revenue and other

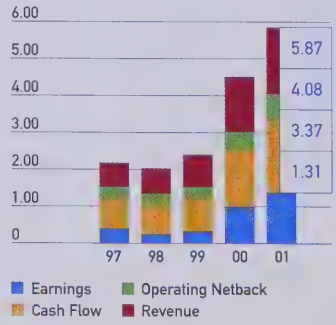
NET CAPITAL EXPENDITURES

Net capital expenditures in 2001 totaled $261.2 million, an increase of 5 percent from 2000 capital spending levels of $249.0 million. **Exploration and development capital expenditures totaled $272.3 million, 65 percent ($177.5 million) of which was devoted to drilling, geological and geophysical activities, and Crown land purchases.** The remaining $94.8 million was spent on pipelines and facilities projects. Paramount continued its commitment to pure exploration activities, directing close to 10 percent of its capital spending, or $25 million, to the pursuit of opportunities outside of the Company's established core areas.

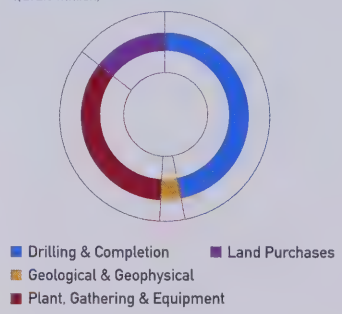
Paramount successfully negotiated 13 separate acquisitions, 3 dispositions and 14 swap transactions in 2001 for a net cost of $7.3 million. As in past years, the focus of the asset rationalization program was to increase working interest within Paramount's existing properties, grow undeveloped land within the Company's active core areas, and optimize facilities utilization.

Using an estimated gas price of $2.50/Mcf, the Company is anticipating cash flow from operations of $185 to $200 million in 2002. This does not include any compensation for the Surmont shut-in order. The 2002 capital budget mimics the current cash flow forecast but will be reassessed after the impact of the first quarter drilling program on 2002 forecast production volumes can be evaluated, coupled with any adjustments to the Company's natural gas price predictions.

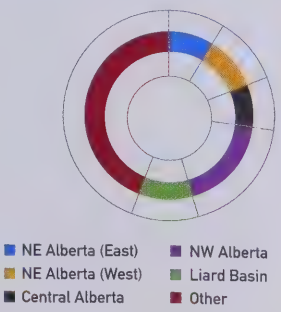
Revenue Reconciliation
($/Mcfeq)



2001 Exploration and Development Expenditures
($272.3 million)



Net Undeveloped Land
(3,765 thousand acres)



LAND

Paramount's land inventory at year end 2001 totaled 5.0 million net acres, an increase of 7 percent from year end 2000. Paramount expanded its undeveloped land base in 2001 through participation in Crown land sales, industry farm-ins and asset acquisitions. **The undeveloped land inventory at December 31, 2001, increased 5 percent, or approximately 168,000 acres from December 31, 2000.** Approximately 45 percent of the undeveloped land base is located outside of existing core areas, representing pure exploration acreage with defined drilling prospects.

Land (thousand acres)	2001			2000		
	Gross	Net	Average working interest	Gross	Net	Average working interest
Land assigned reserves	1,675	1,218	73%	1,472	1,051	71%
Undeveloped land	4,901	3,765	77%	4,744	3,597	76%
Total	6,575	4,984		6,216	4,648	
Fair market value of undeveloped land ($ millions)		100.9			84.9	

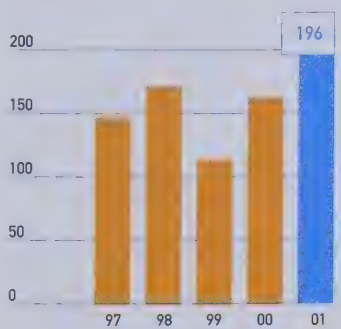
DRILLING

Paramount participated in a total of 196 gross (158.7 net) wells in 2001, 92 percent of which are potential oil or gas wells. This 20 percent increase in drilling activity was concentrated in Central and Northwest Alberta, accounting for over 70 percent of the Company's total number of wells at an average working interest of 82 percent. Drilling in Northeast Alberta, historically Paramount's most active region, represented only 22 percent of the total activity. An additional five gross (1.1 net) wells were drilled on potential high impact exploration prospects outside of established core areas.

Drilling Results	2001		2000	
	Gross	Net	Gross	Net
Exploratory				
Gas	66	52.6	88	71.6
Oil	5	4.3	2	0.5
Service/standing	1	0.5	–	–
D&A	12	7.4	23	20.5
Total exploratory	84	64.8	113	92.6
Success rate	86%		80%	

(Drilling results table continued on page 26)

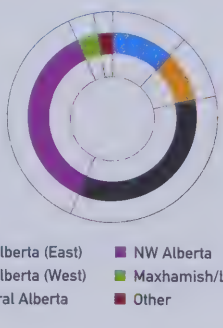
Wells Drilled
(gross)



Drilling Success
(%)



Drilling Distribution



Drilling Results (continued)	2001 Gross	2001 Net	2000 Gross	2000 Net
Development				
Gas	101	84.4	37	27.0
Oil	7	6.1	9	5.8
Service/standing	–	–	2	1.3
D&A	4	3.5	2	2.0
Total development	112	94.0	50	36.1
Success rate (gross)	96%		96%	
Total all well categories	196	158.7	163	128.7
Success rate (gross)	92%		85%	

GEOPHYSICAL

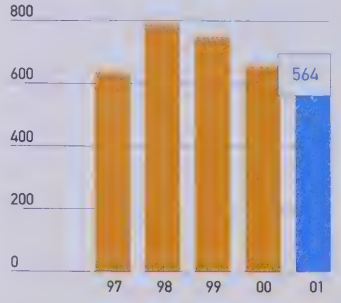
Paramount utilizes two-dimensional ("2D") and three-dimensional ("3D") seismic as well as other geophysical surveys to delineate geological features and increase the certainty of its drilling prospects. **During 2001, Paramount acquired 3,478 kilometers of 2D and 489 square kilometers of 3D seismic data via the trade seismic market or through field acquisition, up 3 percent and 195 percent respectively from 2000 seismic acquisition levels.** In addition, non-seismic geophysical activities, including over 56,280 line kilometers of resistivity and aeromagnetic surveys, were acquired. The majority of this activity took place at Colville Lake in the Northwest Territories and in Northwest Alberta. Total geophysical expenditures in 2001, net of data sales, were $8.7 million net to Paramount, up 74 percent from 2000 reflecting the significant increase in new shoot 3D seismic data and the increased use of other innovative geophysical techniques.

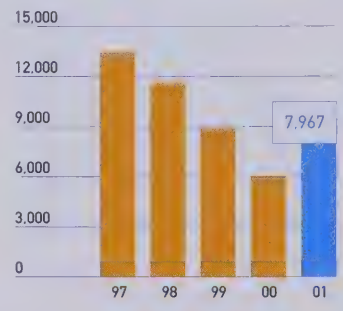
RESERVES

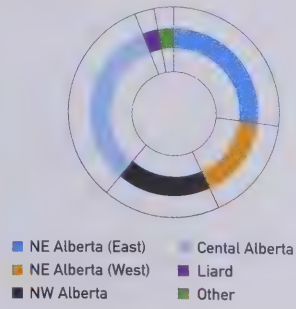
The net effect of reserve additions from the 2001 capital program, negative reserve revisions and 2001 production of 90.0 Bcfeq is a 10 percent reduction in proved and probable reserves to 643.4 Bcfeq at December 31, 2001, from 717.2 Bcfeq at year end 2000. As has been the case since the Company's inception, Paramount's reserves were evaluated by McDaniel & Associates Consultants Ltd.

Proved and probable natural gas reserves decreased 14 percent from a year-end 2000 total of 657.4 Bcf to 563.7 Bcf at year end 2001 as negative revisions of 59.6 Bcf offset natural gas reserve additions of 46.0 Bcf. The most significant negative revisions were at Cameron Hills, Liard and East Legend. Crude oil and natural gas liquids increased 33 percent to 7,967 MBbl at December 31, 2001, from 5,980 MBbl at year end 2000, including reserve additions of 2,542 MBbl and positive reserve revisions of 195 MBbl.

Natural Gas Reserves (Bcf)	2001 Bcf	2001 % of Total	2000 Bcf	2000 % of Total
Proved: producing	298.9	53	338.5	52
non-producing, undeveloped	138.8	25	179.6	27
Total Proved	437.7	78	518.1	79
Probable additional	126.0	22	139.3	21
Total Proved and Probable	563.7	100	657.4	100







Crude Oil and Liquids Reserves (MBbl)	2001		2000	
	MBbl	% of Total	MBbl	% of Total
Proved: producing	5,063	64	4,290	72
non-producing, undeveloped	1,276	16	419	7
Total Proved	6,339	80	4,709	79
Probable additional	1,628	20	1,271	21
Total Proved and Probable	7,967	100	5,980	100

NET ASSET VALUE

Paramount's net appraised asset value at year end 2001 decreased 26 percent from year-end 2000 to $10.99 per share. The decrease in the Company's reserve value was a result of lower overall reserve levels as well as a predicted decrease in the commodity prices that these reserves can expect to receive.

Items worthy of note are:

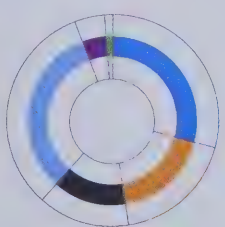
(i) Reserve values were determined by McDaniel & Associates Consultants Ltd. (McDaniel) as at January 1, 2002, using the escalating price forecast in effect by McDaniel at that date.
(ii) The value of the Surmont shut-in gas reserves was determined by McDaniel using the escalating price forecast in use by them as at May 1, 2000, which is significantly lower than current prices.
(iii) No value has been assigned to East Lost Hills, California.
(iv) No value is assigned to tangible assets other than those associated with proved producing reserves.
(v) Paramount's hedging activities, which extend past year end 2001 have not been valued by McDaniel.
(vi) Surmont compensation, which has been determined subsequent to year end, is not included

Paramount has historically utilized debt funding as leverage to add shareholder value. Prudent debt financing will continue to be a key component of Paramount's capitalization. We believe this leverage will translate into additional value for the Company as reserves are booked and cash flow is realized.

Net (Appraised) Asset Value (millions of dollars as at December 31)	2001	2000
Reserve value, before royalties[1]	$ 822.4	$ 1,081.4
Market value of short-term investments	29.6	43.6
Alberta Royalty Tax Credit (ARTC)[1,2]	3.4	3.4
Fair market value of undeveloped land	100.9	84.9
Subtotal	956.3	1,213.3
Working capital (deficiency)[3]	13.8	(19.6)
Total assets	970.1	1,193.7
Bank loan	(316.6)	(315.0)
Net (appraised) asset value	$ 653.5	$ 878.7
Net (appraised) asset value per basic common share[4]	$ 10.99	$ 14.78

(1) @ 15 percent discount (2) ARTC: only on proved reserves (3) Inventory of material and equipment has been reclassified to property and equipment
(4) Outstanding shares: 2000 and 2001 – 59,453,600

Reserve Value
(discounted @ 15%, before tax)
($825.8 million)

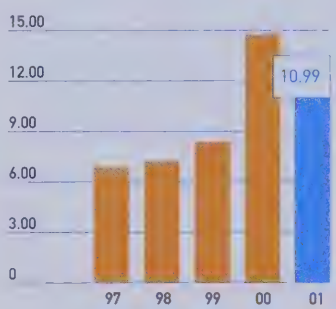


NE Alberta (East)
NE Alberta (West)
NW Alberta
Central Alberta
Liard
Other

Fair Market Value, Undeveloped Lands
($ millions)

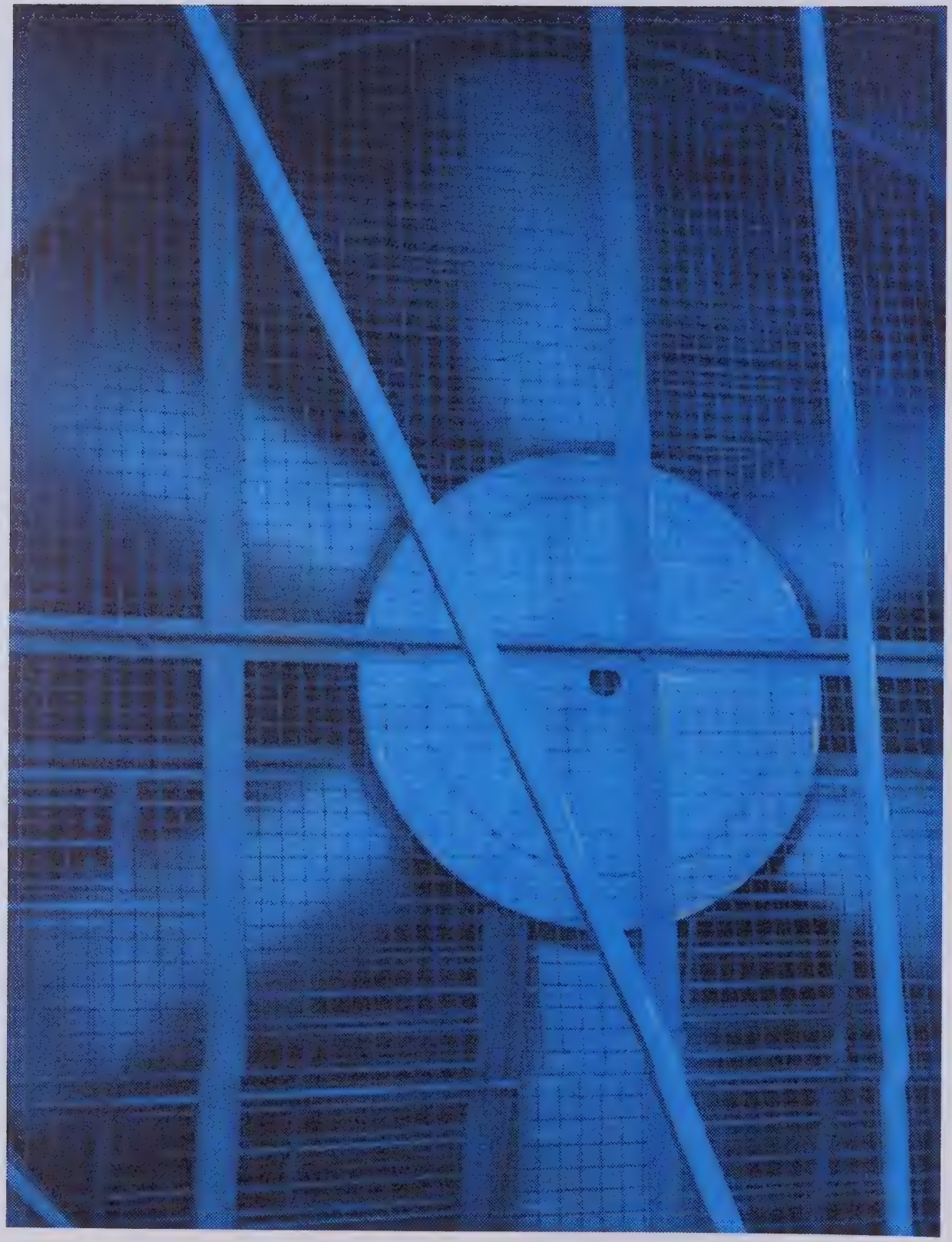


Net (Appraised) Asset Value
($/share)




PARAMOUNT RESOURCES 11.08.2001
CALGARY
TEMPERATURE +6° C
HIGH/LOW $14.30 / $14.00
VOLUME 20,450 SHARES


PARAMOUNT RESOURCES
NORTHWEST ALBERTA
TEMPERATURE
-4° C
GAS PRODUCTION
30.7 MMcf/d
AVERAGE GAS PRICE
$3.00/Mcf



EXPLORATION IN REVIEW

CORE AREAS

Paramount continues to generate numerous exploratory prospects within our traditional core operating areas. Both exploratory drilling and seismic acquisition are ongoing within the following project areas:

1) Central Alberta; Kaybob, Kaybob North, Pine Creek, Tony Creek and Sturgeon Lake.
2) Northwest Alberta: Shetland, Negus/Hutch, West Bistcho, Esk Lake and Cameron Hills.
3) Liard Basin: Liard, Maxhamish,Tattoo, Bovie Lake and Arrowhead.

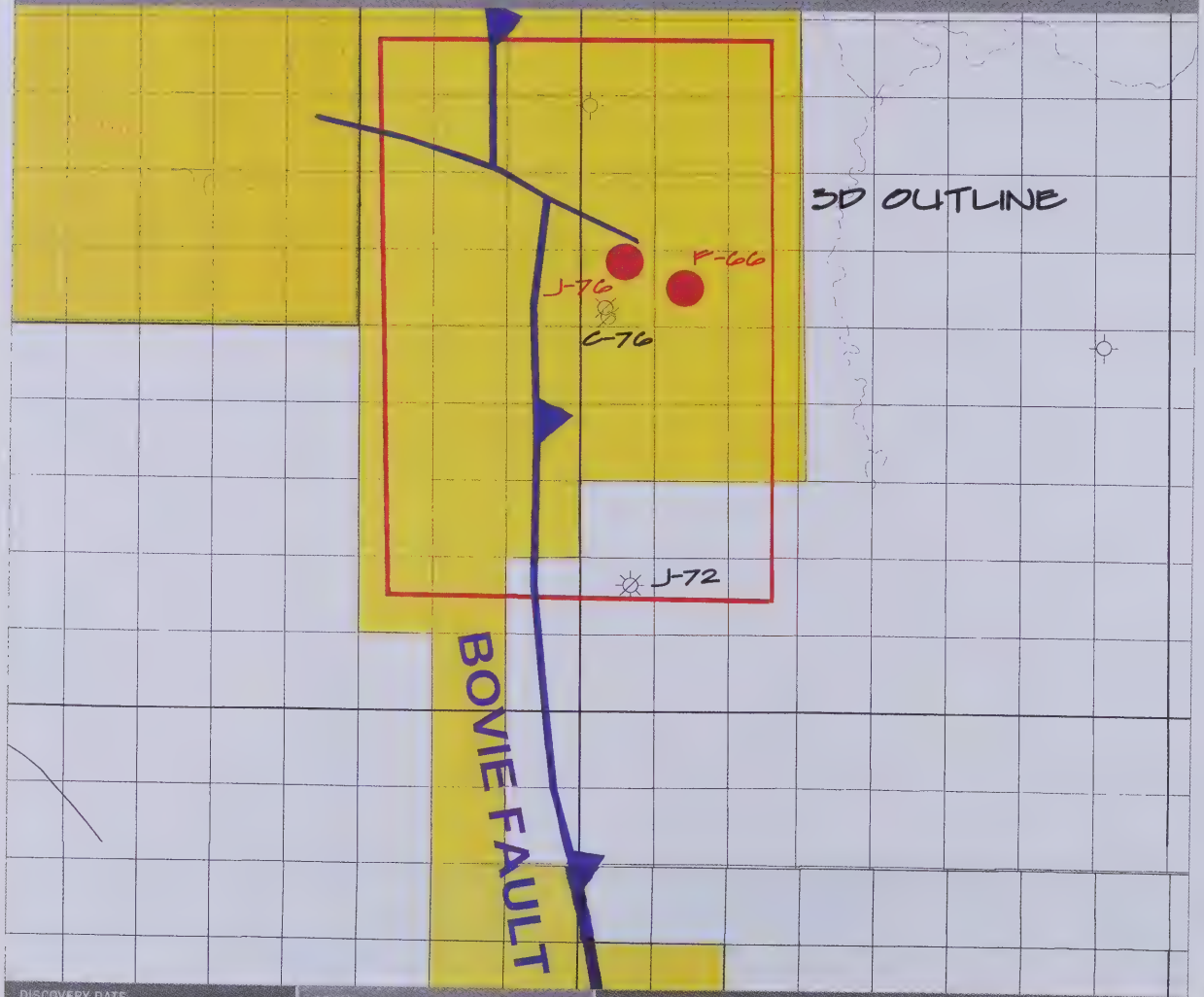
PURE EXPLORATION

In 2001, nearly 10 percent of the annual capital spending was dedicated to pure exploration prospects outside of our established core areas. Exploratory drilling in the US is continuing on the East Lost Hills and Pyramid prospects in California and the Pine Ridge prospect in Wyoming. At Colville Lake, in the Northwest Territories, new seismic data was shot and confirmed multiple exploration locations for future drilling. Additional seismic interpretation on various new play concepts in Northeast British Columbia and the shallow gas trend in Alberta has detailed exploratory locations to be drilled in 2002.

PURE EXPLORATION PROSPECT INVENTORY

EXPLORATION PROJECT	DESCRIPTION	AVERAGE WORKING INTEREST
Shallow Gas Alberta	Paleozoic subcrop and Cretaceous stratigraphic gas traps. Drilling depths less than 2,000 ft (600m)	45 to 100%
Southern Alberta Foothills	Cretaceous, Mississippian and Devonian thrust-faulted targets. Drilling depths up to 16,400 ft (5,000m)	20 to 25%
NEBC Multi-zone	Multi-zone Devonian, Mississippian and Triassic plays. Drilling depths up to 10,000 ft (3,000m)	50 to 100%
Colville Lake, NWT	Cambrian stratigraphic and structural gas/condensate traps. Drilling depths up to 5,900 ft (1,800m)	100%
Powder River Basin, Wyoming	Pennsylvanian structural traps and deep subthrust plays. Drilling depths up to 16,000 ft (4,900m)	87.5%
San Joaquin Basin, California	Deep structural gas/oil play targeting thick Tertiary sands. Drilling depths up to 20,000 ft (6,000m)	13 to 27%

BOVIE LAKE, NWT



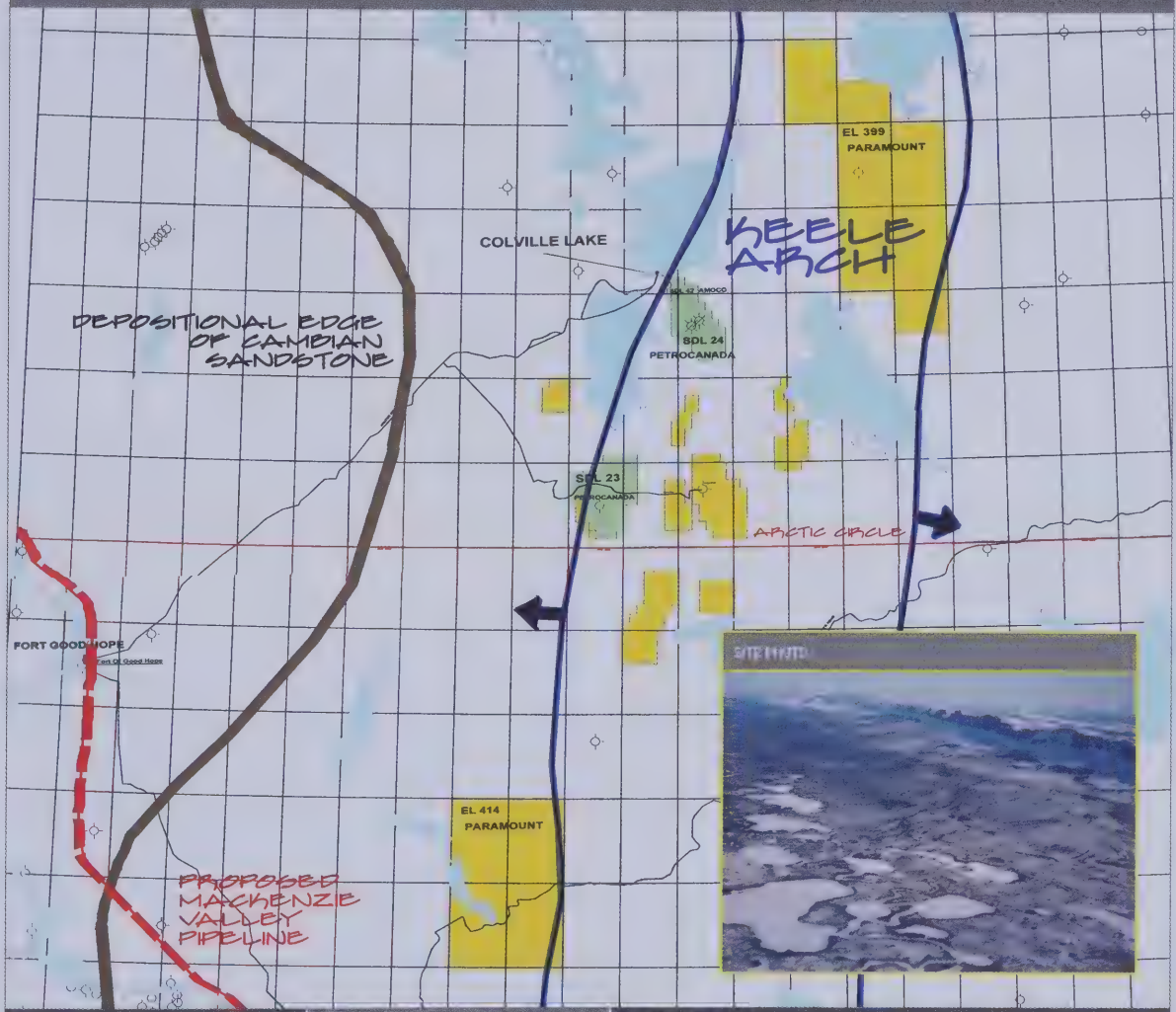
DISCOVERY DATE	1967
AVERAGE DRILL DEPTH	10,920 ft (3,300 m)
TARGET ZONES	Devonian
AVERAGE WORKING INTEREST	50%
ANTICIPATED WELL DELIVERABILITY	10 to 20 MMcf/d
PROSPECT RESERVE POTENTIAL	100 to 200 Bcf
ANTICIPATED INITIAL PRODUCTION	April 2004

PLAY DESCRIPTION

The Bovie project area is located in the NWT 30 km north of the B.C. border along the main Bovie Fault zone. Two locations at J-76 and F-66 target structurally and stratigraphically trapped Devonian gas. Previous gas shows were encountered in the Devonian at J-72 (1967) and C-76 (1999). A 116 square km 3D program shot in 2000 was used to select the current drilling locations.

Both the J-76 and F-66 wells have been cased to total depth at approximately 3,200 m and should have completion operations concluded before spring breakup in April 2002.

COLVILLE LAKE, NWT



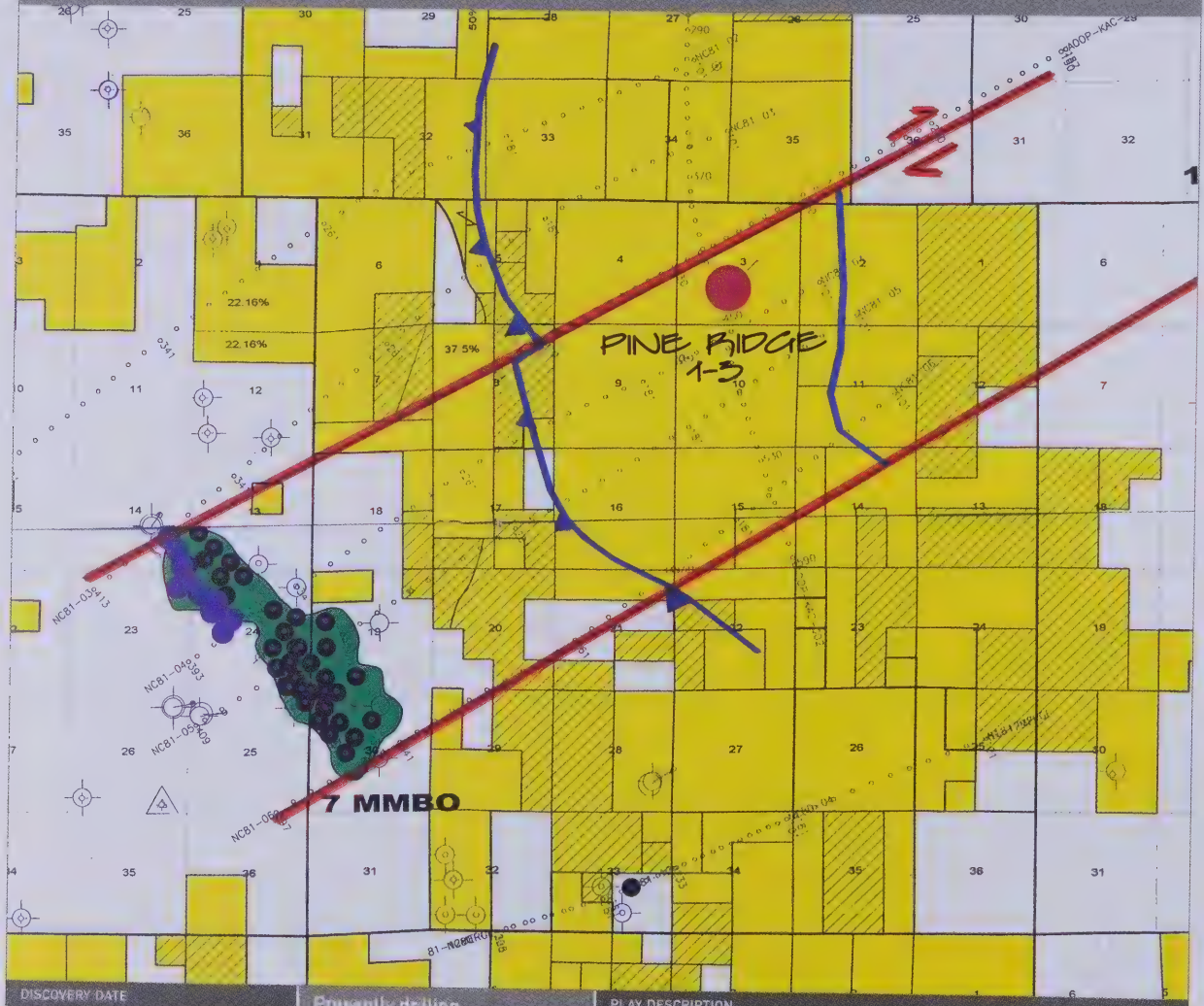
DISCOVERY DATE	1985
AVERAGE DRILL DEPTH	3,900 ft (1,200 m)
TARGET ZONES	Cambrian Sandstones
AVERAGE WORKING INTEREST	100%
ANTICIPATED WELL DELIVERABILITY	3 to 10 MMcf/d
PROSPECT RESERVE POTENTIAL	50 to 500 Bcf
ANTICIPATED INITIAL PRODUCTION	2006

PLAY DESCRIPTION

Situated at the Arctic Circle, the Colville Lake area has significant potential for large-scale gas and condensate reserves trapped structurally and stratigraphically within basal Cambrian sandstones. The area is vastly underexplored yet it has yielded estimated reserves of over 200 Bcf in three discoveries. In 2001, Paramount added to its significant land base by successfully acquiring an additional Federal Exploration License, EL414. With this acquisition, Paramount now holds over 650,000 acres (~28 Alberta Townships) at a 100% working interest.

In 2001, Paramount acquired 120 km of high-resolution 2D seismic. This new data together with 280 km of newly reprocessed trade data helped identify multiple drilling locations. One of the locations, originally slated to be drilled during the winter of 2002, was deferred to the next drilling season due to local rig availability.

POWDER RIVER BASIN, WY



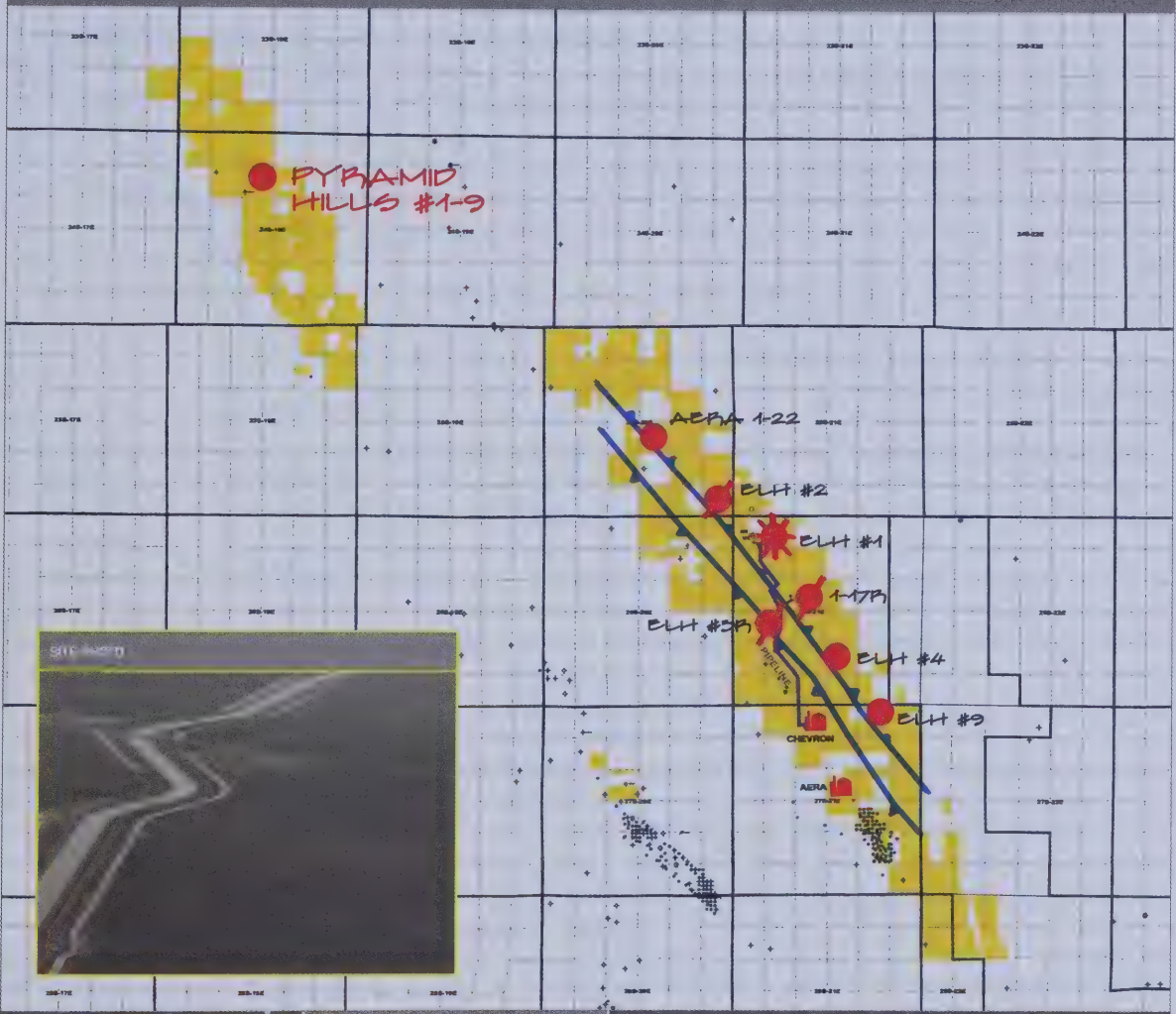
DISCOVERY DATE	Presently drilling
AVERAGE DRILL DEPTH	16,400 ft
TARGET ZONES	Minnelusa/Tensleep
AVERAGE WORKING INTEREST	87.5%
ANTICIPATED WELL DELIVERABILITY	250 to 400 Bbl/day
PROSPECT RESERVE POTENTIAL	2 to 4 MMBbls
ANTICIPATED INITIAL PRODUCTION	September 2002

PLAY DESCRIPTION

Oil accumulations in the thick Pennsylvanian Minnelusa/Tensleep formation are the target of the well currently drilling in section 3 T44R82. Several nearby fields produce from the same formation as shown on the map. The trapping is provided by structural roll-over and faulting and pool size could range from one to five sections. Pipeline facilities are available nearby.

Current drilling operations should be concluded in mid-April, 2002. If the Pine Ridge 1-3 test proves successful, Paramount has already identified additional prospects similar to this which it may capitalize on.

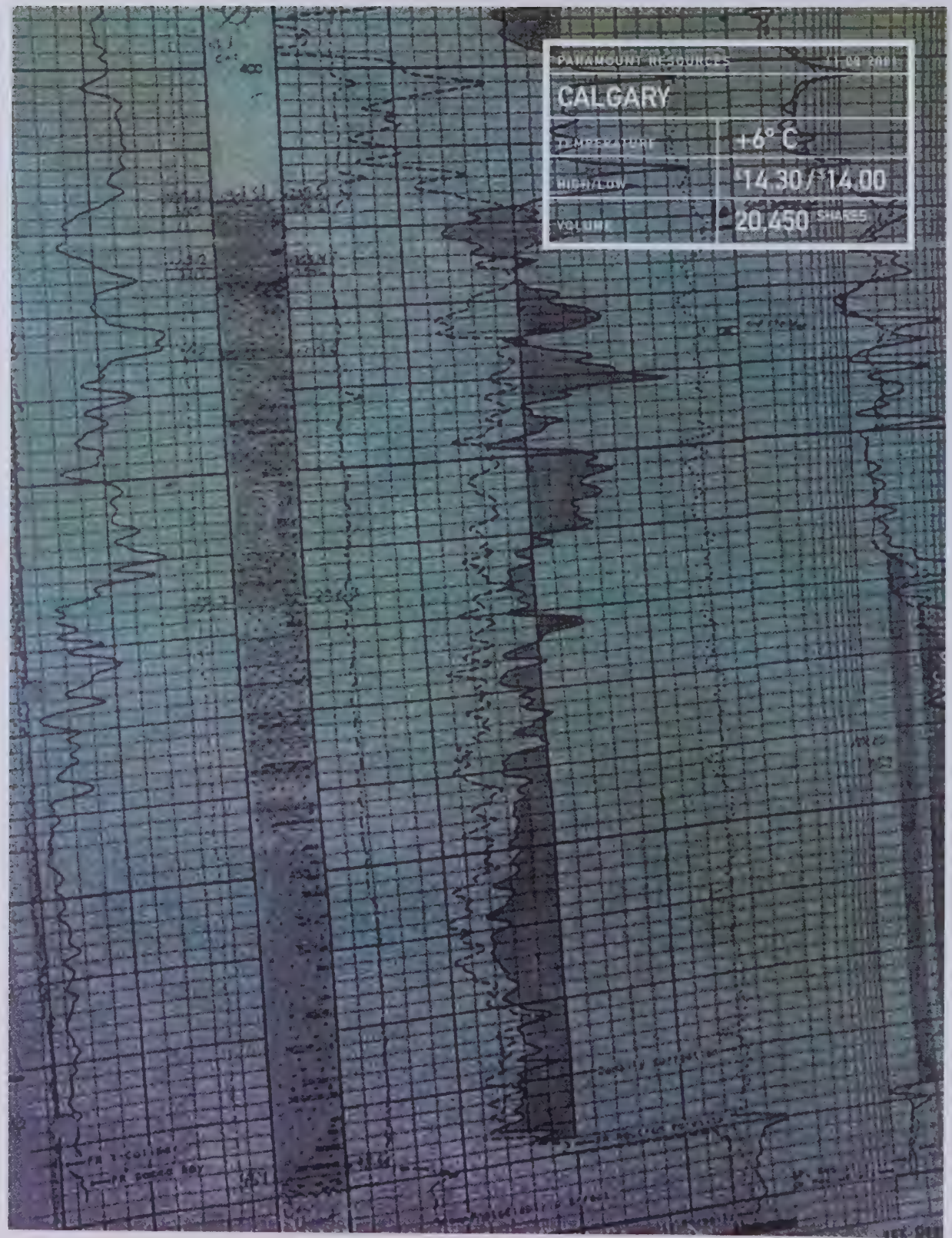
SAN JOAQUIN BASIN, CA



DISCOVERY DATE	1998
AVERAGE DRILL DEPTH	20,000 ft (6,000 m)
TARGET ZONES	Tertiary Temblor
AVERAGE WORKING INTEREST	13 to 27%
ANTICIPATED WELL DELIVERABILITY	25 MMcf/d
PROSPECT RESERVE POTENTIAL	350 million to 1 billion BOE
ANTICIPATED INITIAL PRODUCTION	February 6, 2001

PLAY DESCRIPTION

ELH #1 has been producing from the lower Temblor formation since February 6, 2001. Cumulative production to year end was 1.4 Bcf of gas. ELH #2 penetrated only the upper Temblor section, tested gas at low rates and has been temporarily shut in. ELH #3 tested a new pool to the west of the existing East Lost Hills field. The Temblor was present but tight, resulting in the temporary suspension of this well. ELH #4 has been drilled and cased and will be completed in spring 2002. ELH #9 is still drilling at the south end of the pool and has encountered encouraging gas shows. At Pyramid Hills, a new field wildcat is currently being drilled and should be completed in 2002.


PARAMOUNT RESOURCES
CALGARY
TEMPERATURE
+6° C
HIGH/LOW
14.30 / 14.00
VOLUME
20,450 SHARES


PARAMOUNT RESOURCES
11.08.2011
LIARD/MAXHAMISH
TEMPERATURE
-7° C
GAS PRODUCTION
12.8 MMcf/d
AVERAGE GAS PRICE
$3.45/Mcf



MANAGEMENT'S DISCUSSION & ANALYSIS

HIGHLIGHTS

Paramount Resources Ltd. (the "Company") is an exploration, development and production company with established operations in Alberta, British Columbia, Saskatchewan, the Northwest Territories and California. During the past 23 years, the Company has patiently executed its corporate growth strategy, focusing on natural gas as a commodity, and exploration as the vehicle to success. Management's vision was, and continues to be, based on the long-term requirement for natural gas in North America. As such, Paramount continues to focus its efforts on building a strong asset base that will fuel growth through exploration and development, increasing reserves and production.

During 2001, Paramount experienced its most profitable year ever. The hangover from the supply/demand imbalances in late 2000 continued with unprecedented prices being received for natural gas during the first quarter. As natural gas prices retreated during the remaining three quarters, Paramount's natural gas hedge, put in place in the fourth quarter of 2000, provided an additional $15.8 million in pre-tax profits.

- Paramount remains highly leveraged to natural gas with approximately 95 percent of revenue from natural gas sales
- Cash flow increased 36 percent to $303.9 million or $5.11 per basic common share ($5.11 per diluted common share)
- Net earnings totaled $118.9 million or $2.00 per basic common share ($2.00 per diluted common share)
- A Memorandum of Agreement has been reached with Alberta Crown and Conoco Canada Resources Ltd. providing approximately $44 million in compensation for the shut-in of 22 MMcf/d of natural gas sales in May 2000.

For 2002, Paramount's business plan will focus on managing cash flow and capital expenditures assuming that natural gas prices will remain in the US $2.50/Mcf range until gas storage levels are reduced. In this environment the Company's priority is a systematic approach to creating opportunities which will enable Paramount to capitalize on future demand for natural gas.

For the purpose of comparing the Company's revenues and costs on a unit-of-production basis, crude oil and liquids volumes have been converted to natural gas (Mcfeq) on the basis that one barrel of oil equals 10 Mcf of gas.

ACCOUNTING POLICY

Paramount follows the "successful efforts" method of accounting for its petroleum and natural gas operations. This method, unlike the alternative "full cost" accounting method, usually generates a more conservative value for net earnings as exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases and abandoned wells are expensed rather than capitalized in the year incurred. However, to make reported cash flow results comparable to industry practice, Paramount reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities.

BITUMEN/NATURAL GAS CO-PRODUCTION

On April 3, 2000, the AEUB delivered its decision on the application of Gulf Canada Resources Ltd. to shut in natural gas wells in the Surmont area on the premise that continued gas production would adversely affect the recovery of heavy oil within the McMurray formation. As a result of the decision, Paramount complied with the order to shut in Wabiskaw-McMurray production from 65 wells that it operates in the affected area. An additional 81 non-operated wells were also ordered to be shut in, 12 of which Paramount has an interest in.

This resulted, effective May 1, 2000, with the shut in of approximately 22 MMcf/d of natural gas production net to Paramount from leases lawfully purchased from the Province of Alberta and diligently developed over the past 20 years in full compliance with the rights granted by the Province.

On February 28, 2002, Paramount Resources Ltd. entered into a Memorandum of Agreement with the Province of Alberta and Conoco Canada Resources Ltd. ("Conoco"), effective May 1, 2000. The Memorandum of Agreement provides, inter alia, for compensation of $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, lands and leases affected by the shut-in order of May 1, 2000. Paramount is entitled to slightly over half the compensation.

The Memorandum of Agreement remains conditional on the Surmont Gas Producers and Conoco entering into an agreement governing their relationship relative to Conoco's commercial production of the bitumen resource. All parties must also agree on what will be required for the shut-in gas production to resume and, in this context, must reach consensus on defining the parameters of a technical solution acceptable to all. Consequently, Paramount has not made any provision in the financial statements to reflect compensation.

REVENUE

Production Revenue (thousands of dollars)	2001	2000	1999
Natural gas	$ 484,123	$ 375,746	$ 194,297
Crude oil and natural gas liquids	28,442	21,676	16,018
Natural gas hedging gain (loss)	15,808	(5,952)	1,343
	$ 528,373	$ 391,470	$ 211,658

Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The hedging program is generally for periods of less than one year and restricted as to a maximum of 50 percent of Paramount's current production volumes.

Petroleum and natural gas revenue increased 35 percent in 2001 to $528.4 million from $391.5 million in 2000 (1999 – $211.7 million). The increase is attributable to higher natural gas prices as sales volumes increased only marginally year over year. Paramount's 2001 production profile was significantly weighted to natural gas with approximately 95 percent of the Company's sales attributable to this commodity. Fourth quarter petroleum and natural gas sales totaled $87.7 million as compared to $151.8 million in 2000. The reduction in sales results entirely from natural gas commodity prices, which averaged $3.03/Mcf during the quarter as compared to $7.46/Mcf for the comparable quarter in 2000.

Natural gas sales averaged 225 MMcf/d in 2001 as compared to 220 MMcf/d in 2000 (1999 – 220 MMcf/d). Stronger natural gas demand and the Company's hedging initiatives in 2001 resulted in an increase of 151 percent in Paramount's average natural gas sales price to $6.12/Mcf as compared to $4.59/Mcf in 2000 (1999 – $2.43/Mcf). Included in the price is approximately $0.19/Mcf profit from natural gas commodity hedges that were in place during 2001. The hedges included 120 MMcf/d of natural gas at NYMEX at an average price to October 2001 of US $4.88/Mcf or $6.85/Mcf AECO after fixing the NYMEX/AECO basis on 100 million cubic feet per day. For the year ended December 31, 2001, gross revenue includes gains from commodity hedging activity of $15.8 million (2000 – $6.0 million loss). Fourth quarter hedging gains totaled $22.6 million.

At December 31, 2001, Paramount had the following natural gas commodity price hedges in place representing approximately 45 percent of Paramount's average 2001 production:

Volume	Price	Term
AECO		
80,000 Giga joules per day ("GJ/D")	$ 4.3825	January 1, 2002 – December 31, 2002
10,000 GJ/D	$ 3.6850	January 1, 2002 – December 31, 2002
NYMEX		
5 MMcf/d	US $ 3.63	September 1, 2001 – October 31, 2002
10 MMcf/d	US $ 3.66	September 1, 2001 – October 31, 2002
10 MMcf/d	US $ 3.67	September 1, 2001 – October 31, 2002

The unrealized gain on these financial hedges at December 31, 2001 totalled $35.4 million. In addition, Paramount crystalized a US $25.7 million basis premium associated with a NYMEX financial basis swap on volumes into California. The premium will be received and recorded into income over the term of the related swap, primarily 2002. During the fourth quarter, Paramount closed out AECO hedges totaling 80 MMcf/d at a loss of $17.6 million. This loss has been deferred and will be amortized into income over the term January – December 2002.

The Company also has in place foreign exchange hedges, which have fixed the exchange rate on US $27.8 million for Cdn. $39.7 million over the next three years at Cdn. $1.4264. For the year ended December 31, 2001, gross revenue included losses from foreign currency hedging activity of $1.7 million (1999 – $1.2 million).

During 2001, approximately 42 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 46 percent and 55 percent for 2000 and 1999, respectively.

Natural Gas Sales per Market Group		2001 Bcf	2001 %	2000 Bcf	2000 %	1999 Bcf	1999 %
Long-term contracts							
Aggregators							
Mirant	Midwestern US, Pacific Northwest US California and Quebec	17.4	21.2	19.6	24.3	23.1	28.8
Progas	Northeastern US	8.1	9.9	7.2	8.9	8.4	10.6
Canstates/Temco	Northeastern US	1.9	2.2	3.2	4.0	4.5	5.7
TransCanada	Eastern Canada	2.7	3.3	1.2	1.5	1.8	2.3
Subtotal – aggregators		30.1	36.6	31.2	38.7	37.8	47.4
Direct sales Selkirk	New York State	4.5	5.5	6.0	7.4	6.3	8.0
Subtotal – Long-term Contracts		34.6	42.1	37.2	46.1	44.1	55.4
Short-term markets							
Spot	California	14.6	17.8	14.6	18.1	15.5	19.6
Spot	Alberta/Waddington	32.9	40.1	28.7	35.8	20.7	25.0
Total[1]		82.1	100.0	80.5	100.0	80.3	100.0

(1)Natural gas sales for 2000 reflect a 366-day year

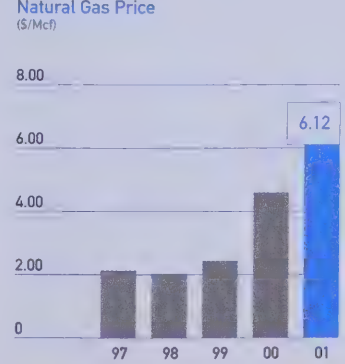
Petroleum and natural gas liquid sales averaged 2,165 Bbl/d, an increase of 38 percent from 1,571 Bbl/d in 2000 (1999 – 1,854 Bbl/d). The Company's average liquids price in 2001 decreased 6 percent to $35.48 per barrel from $37.80 per barrel in 2000 (1999 – $24.27 per barrel), consistent with a decrease in the average West Texas Intermediate (W.T.I.) price. The W.T.I. price for crude oil averaged US $25.93 per barrel during 2001, down from US $30.30 per barrel in 2000 (1999 – US $19.26 per barrel).

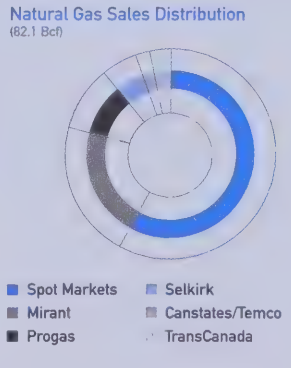
Revenues in 2002 will be impacted by drilling success and production volumes as well as external factors such as the market for natural gas, the exchange rate of the Canadian dollar relative to the US dollar and the W.T.I. price for crude oil. Although the Company anticipates a continued positive trend in natural gas prices for 2002 relative to the last half of 2001, prices are not expected to mirror those received in early 2001. As the economic environment improves and industrial demand in the United States increases, pricing will improve to reflect any supply/demand imbalance. Paramount has access to US-priced gas sales through aggregator contracts and direct sales and is well positioned to benefit from future price increases.

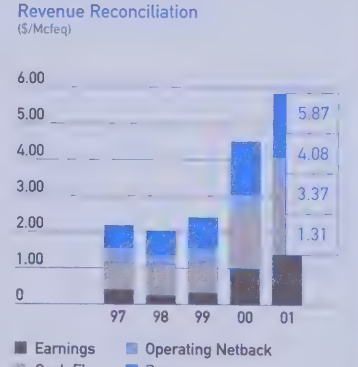
ROYALTIES

Royalties are paid by Paramount to the owners of mineral rights with whom the Company holds leases. Paramount has mineral leases with the Crown (Provincial and Federal Governments), freeholders and other operators with whom the Company has joint interests.

Royalties (thousands of dollars)	2001	2000	1999
Crown royalties	$ 94,253	$ 76,470	$ 35,274
Other royalties	5,953	4,587	3,670
	100,206	81,057	38,944
Alberta Royalty Tax Credit	(500)	(516)	(1,377)
Total royalties	$ 99,706	$ 80,541	$ 37,567
Average corporate royalty rate	18.87%	20.57%	17.75%







Alberta gas Crown royalties are a cash royalty calculated on the Crown's share of production using the Alberta Reference Price. The Alberta Reference Price is the monthly weighted average price for gas consumed in Alberta and gas exported from Alberta reduced for allowances for transportation and marketing. A subsequent cost-of-service credit is applied to account for the Crown's share of allowable capital and processing fees to arrive at the net royalty.

During 2001, Paramount's average natural gas price of $6.12/Mcf exceeded the Alberta Natural Gas Reference Price of $5.12/GJ or approximately $5.38/Mcf. As royalties are only calculated and paid based on the Alberta Reference Price, any revenue received in excess of the Alberta Reference calculation are not subject to royalties, thereby reducing the corporate average royalty rate.

For 2001, royalties net of the Alberta Royalty Tax Credit ("ARTC") increased to $99.7 million from $80.5 million in 2000 (1999 – $37.6 million) due to higher natural gas commodity prices. As a percentage of production revenue, however, Paramount's corporate royalty rate decreased to 18.87 percent as compared to 20.57 percent in 2000 (1999 – 17.75 percent). Fourth-quarter royalties mirrored the reduction in natural gas prices and decreased to $12.4 million as compared to $21.9 million during the fourth quarter 2000.

For 2002, Paramount's average corporate royalty rate is expected to increase, giving effect to a corporate average price that approximates the Alberta Natural Gas Reference Price. This will then be significantly reduced by the expected Surmont compensation, which should come in the form of reduced royalties. As in 2001, there will continue to be minimal royalties paid to the Federal Government for production from projects in the Northwest Territories. Royalties for these projects are subjected to payout accounts.

OPERATING EXPENSES

Operating Expenses (thousands of dollars)	2001	2000	1999
Operating expenses	$ 61,045	$ 47,974	$ 39,030
Net operating expenses per Mcfeq	$ 0.68	$ 0.56	$ 0.45

Paramount's 2001 operating expenses increased 27 percent to $61.0 million from $48.0 million in 2000 (1999 – $39.0 million). On a unit-of-production basis, average operating costs increased to $0.68/Mcfeq from $0.56/Mcfeq in 2000 (1999 – $0.45/Mcfeq). Fourth-quarter operating costs increased to $17.5 million as compared to $13.5 million a year earlier. Seasonal maintenance and turnaround costs were incurred during the quarter and are largely responsible for the increase.

Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs. As production declines in the Company's traditional shallow gas areas, per-unit operating costs have increased. In new core areas, facilities are constructed in anticipation of maximizing throughput, which in many cases has not yet been achieved. As optimization occurs and production volumes increase, per-unit costs should decrease to levels historically experienced by the Company.

GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses (thousands of dollars)	2001	2000	1999
Gross general and administrative expenses	$ 26,374	$ 18,982	$ 15,771
Operating recoveries	(15,765)	(11,369)	(8,927)
General and administrative expenses before SARP	10,609	7,613	6,844
Share Appreciation Rights Plan ("SARP")	1,738	2,047	1,722
Net general and administrative expenses	$ 12,346	$ 9,660	8,566
Net general and administrative expenses per Mcfeq	$ 0.14	$ 0.11	$ 0.10

General and administrative expenses, net of operating recoveries and before costs associated with the Share Appreciation Rights Plan, ("SARP") increased to $10.6 million in 2001 as compared to $7.6 million in 2000 (1999 – $6.8 million). Since 1998, the Company has increased head office staff by more than 50 percent and field staff by 40 percent in order to manage the Company's increasing asset base adequately and to execute the larger capital expenditure programs. Cost increases are primarily due to increased administrative costs associated with additional staffing levels including salary, benefits and rent. Paramount does not capitalize any general and administrative expenses.

At the Annual General Meeting of the shareholders held June 14, 2001, a resolution was approved to introduce an employee stock option plan as a substitute for the SARP. Share appreciation rights previously held by employees will be grandfathered until their expiry and be capped at a price of $14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and $14.50, which difference is charged to general and administrative expenses. At December 31, 2001, 479,000 SARPs remained outstanding. Employees exercising options have the choice of receiving cash from the Company for the positive difference between the exercise price and market price of the Company shares or receiving Company shares.

Cash consideration paid is charged to general and administrative costs as incurred. During 2001, 329,500 rights were exercised for consideration of $1.7 million as compared to $2.0 million in 2000 (1999 – $1.7 million).

General and administrative expenses before costs associated with the SARP and stock option plan are expected to increase marginally year over year while staff levels keep pace with increased activity levels giving effect to Paramount's growth and aggressive capital expenditure program. Costs on a unit-of-production basis, however, are expected to decrease as the additional costs are offset by higher production volumes.

INTEREST EXPENSE

Interest Expense (thousands of dollars)	2001	2000	1999
Interest expense	$ 19,291	$ 22,313	$ 15,042
Bank loans, December 31	$ 316,600	$ 315,000	$ 267,360
Debt to cash flow	1.04	1.41	2.53

Interest expense, representing interest on bank debt, decreased to $19.3 million from $22.3 million in 2000 (1999 – $15.0 million). The decrease reflects lower average debt levels throughout the year, and significantly lower interest rates charged by the banks. The Company's credit facility bears interest at the bank's prime lending rate, which during 2001 averaged approximately 6.0 percent, compared to 7.23 percent in 2000 (1999 – 6.42 percent). The rate charged Paramount was further reduced by approximately 0.75 percent as a result of the utilization of Bankers Acceptances. Subsequent to September 11, 2001, the prime interest rate averaged 5.3 percent, giving recognition to the economic uncertainty that followed the events of that date. That reduced interest expense during the fourth quarter to $4.7 million as compared to $5.6 million for the equivalent period in 2000. Based on current rates it is expected that interest expense will be lower in 2002. The Company does not anticipate increasing its current debt capacity beyond $330 million. Paramount does not capitalize any interest expense.

DRY HOLE COSTS

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. Geological and geophysical expenses increased during 2001 to $10.6 million (2000 – $6.8 million), primarily due to the acquisition of a large seismic program at Coleville Lake in the NWT and several large geophysical surveys in the Negus area of Northwest Alberta. During 2001, dry hole costs totaled $8.9 million as compared to $7.0 million in 2000 and $10.4 million in 1999. Dry hole costs include adjustments for wells drilled in previous years which have also been determined to be uneconomic.

DEPLETION, DEPRECIATION AND AMORTIZATION

The current year provision for depletion and depreciation expense totaled $105.4 million as compared to $50.6 million in 2000 (1999 – $47.0 million). On a unit-of-production basis, depletion and depreciation costs averaged $1.21/Mcfeq as compared to $0.59/Mcfeq in 2000 (1999 – $0.54/Mcfeq). A larger depletable base and reduced proved reserves increased the depletion factor during the fourth quarter. In addition, the Company recorded a one time charge of $30 million relating to negative revisions to the book value of unproved leases which have been determined to be of lower value. This amount has been recorded to depletion expense for 2001.

Under the successful efforts method of accounting, depletion and depreciation is provided based on estimated proved recoverable reserves of each producing property. Capital costs associated with undeveloped land and non-producing petroleum and natural gas properties totaling $402.0 million are excluded from capital costs subject to depletion in 2001.

For 2002, the provision for depletion and depreciation is expected to increase as a function of continued growth in production volumes and a larger depletable base. Increases or decreases in the depletion rate on a unit-of-production basis will be influenced by the reserves added through the 2002 drilling program or by acquisition.

FUTURE SITE RESTORATION AND ABANDONMENT COSTS

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 2001 the provision totaled $2.4 million as compared to $1.7 million in 2000 (1999 – $1.2 million). Current estimates for site restoration of all the Company's properties total approximately $27 million, of which $9.0 million is reflected as an accumulated provision in the financial statements at December 31, 2001.

INCOME TAXES

In 2001, Paramount recorded current income tax expense, including Large Corporations Tax, of $2.7 million as compared to $2.3 million in 2000 (1999 – $1.6 million).

Paramount's tax pools in 2001 were not sufficient to offset the magnitude of taxable income generated from record profits. As a result, the Company has paid Part 1 cash tax installments of $25 million, representing the estimated tax liability for 2001. An additional $2.7 million in Large Corporations Tax, which is levied on the Company's capital base, was also paid during the year.

The provision for future income taxes totaled $56.1 million as compared to $72.0 million in 2000 (1999 – $18.4 million).

Estimated Income Tax Pools (thousands of dollars)	December 31, 2001
Undepreciated capital costs	$ 245.9
Canadian oil and gas property expenses	221.0
Canadian exploration expenses	–
Canadian development expenses	71.1
Foreign exploration and development expenses	22.4
Other	1.7
Total estimated income tax pools	$ 562.1

Paramount has available approximately $562 million of unutilized tax pools at December 31, 2001. These tax pools, in addition to tax pools generated as a result of the Company's 2002 capital expenditure program, will be available for deduction in 2002 in accordance with Canadian income tax regulations at varying rates of amortization. Based on these tax pools and Paramount's most recent forecast of 2002 financial results and level of capital reinvestment, the Company is not expected to pay current income taxes in 2002.

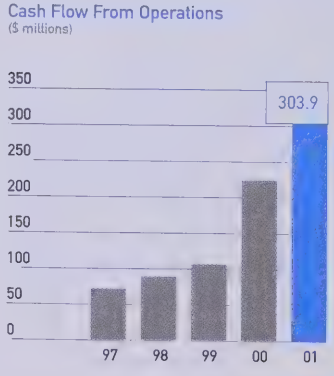
CASH FLOW AND EARNINGS

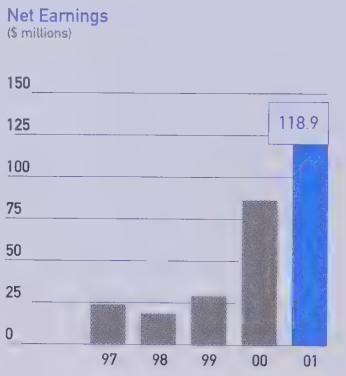
(thousands of dollars)	2001	2000	1999
Cash flow from operations	$ 303,937	$ 223,446	$ 105,830
Net earnings	$ 118,902	$ 86,062	$ 28,683
Weighted average shareholders' equity	$ 477,705	$ 373,623	$ 295,962
After-tax rate of return	24.9	23.0	9.7

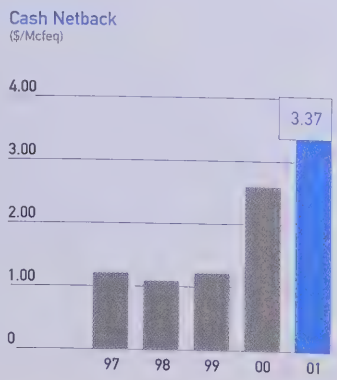
Paramount's cash flow from operations increased 36 percent to $303.9 million or $5.11 per basic common share ($5.11 per diluted common share) from $223.4 million or $3.76 per basic and diluted common share in 2000 (1999 – $105.8 million or $1.84 per basic and diluted common share). Fourth-quarter cash flow totaled $47.7 million, a decrease of 51 percent from $97.2 million during the same period in 2000. The ramp-up in prices during the latter part of 2000 has skewed the results, making quarterly comparisons difficult. The weighted average shares outstanding totaled 59.5 million in 2001 compared to 59.5 million in 2000 (1999 – 57.5 million).

Earnings increased 38 percent to $118.9 million or $2.00 per basic common share ($2.00 per diluted common share) compared to $86.1 million or $1.45 per basic and diluted common share in 2000 (1999 – $28.7 million or $0.50 per basic and diluted common share). Included is a fourth-quarter loss of $14.7 million or $0.20 per basic common share ($0.20 per diluted common share).

Paramount's three-year average after-tax rate of return on a book basis, based upon the weighted average shareholders' equity invested, was 21 percent.







NETBACKS

Netbacks ($/Mcfeq)	2001	2000	1999
Revenue	$ 5.87	$ 4.54	$ 2.43
Royalties (net of ARTC)	1.11	0.93	0.43
Operating costs	0.68	0.56	0.45
Operating netback	4.08	3.05	1.55
General and administrative	0.14	0.11	0.10
Lease rentals	0.05	0.06	0.05
Interest on long-term debt	0.21	0.26	0.17
Current and Large Corporations tax	0.31	0.03	0.02
Cash netback	$ 3.37	$ 2.59	$ 1.21

CAPITAL EXPENDITURES

(thousands of dollars)	2001	2000	1999
Land	$ 39,166	$ 24,016	$ 27,708
Geological and geophysical	10,646	6,784	2,418
Exploration and development drilling	127,736	108,811	86,059
Production equipment and facilities	94,775	92,690	36,508
Exploration and development expenditures	272,323	232,301	152,693
Dry hole and geological and geophysical costs expensed	(19,590)	(13,803)	(12,817)
Property acquisitions	19,048	61,550	31,924
Property dispositions	(11,763)	(34,205)	(1,894)
Other	1,166	3,205	1,173
Net capital expenditures	261,184	249,048	171,079
Adoption of new accounting policy	–	14,900	–
Tax effect of renounced exploration and development	–	–	(14,323)
Change in cost of petroleum and natural gas properties	$ 261,184	$ 263,948	$ 156,756

During 2001, expenditures for exploration and development activities totaled $272.3 million as compared to $232.3 million in 2000 (1999 – $152.7 million). A total of 196 gross (158.7 net) wells were drilled during the year, including 34 gross (30.1 net) wells in the fourth quarter, compared to 163 gross (128.7 net) wells in 2000.

Net capital expenditures, including property acquisitions net of dispositions, amounted to $261.2 million in 2001 as compared to $249.0 million in 2000 (1999 – $171.1 million). Fourth-quarter capital expenditures totaled $59.1 million. The capital expenditure program was financed by internally generated cash flow of $303.9 million.

In October 1999, Paramount issued 2.5 million common shares from treasury pursuant to a flow-through share private placement offering at an average price of $21.87 per share for gross proceeds of $54.7 million. Proceeds from the financing assisted the Company in its 2000 capital expenditure program, which was heavily weighted to the first quarter.

For 2002, Paramount's capital expenditure budget will be funded by internally generated cash flow and minor property dispositions. Any deficiency will draw upon existing credit facilities.

INVESTMENTS

SHORT-TERM INVESTMENTS

The company has the following short-term investments:

	Opening 2001 Shares	Purchased (Sold)	Closing 2001 Shares	Investment	Gain on Sale
Investments:					
Peyto Exploration and Development Corp.	9,159,072	(450,000)	8,709,072	$ 4,932,131	$ 1,250,745
Berkley Petroleum Corp.	1,900,000	(1,900,000)	–	–	1,660,000
Ranchero Energy Corp.	255,600	(255,600)	–	–	71,515
Triquest Energy Corp.	5,000,000	–	5,000,000	3,000,000	–
Fox Creek Petroleum Corp.	–	1,028,571	1,028,571	1,000,000	–
Spearhead Resources Inc.*				5,000,000	
				$ 13,932,131	$ 2,982,260

* Spearhead Resources Inc. $5 million 8 percent secured convertible debenture due September 12, 2003.

At December 31, 2001, the market value of these investments totaled $29.6 million. Subsequent to year end, the Company disposed of an additional 4.2 million shares of Peyto Exploration and Development Corp. for gross proceeds of $18.1 million; these proceeds were used to reduce bank indebtedness.

INVESTMENT IN DRILLING COMPANY

Paramount owns a 50 percent equity interest in Wilson Drilling Ltd., a private company established to operate drilling rigs in Western Canada. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements. The Company's first drilling rig became operational during the first quarter of 1998. Subsequently two additional rigs were added to the fleet in 2001.

INVESTMENT IN PIPELINE COMPANY

Paramount owns a 50 percent equity interest, before payout (45 percent after payout) in Shiha Energy Transmission Ltd., a private company established to transport natural gas from operations in the Liard Core Area, Northwest Territories to facilities in British Columbia. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements. The pipeline became operational in the year 2000.

INVESTMENT IN ENGINEERING COMPANY

Paramount owns a 50 percent equity interest in a private company whose principal business is to provide consulting and technical engineering services. The Company accounts for its interest using proporationate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

DEFERRED REVENUE

During 2001, Paramount recognized in revenue $1.2 million (2000 – $1.2 million; 1999 – $1.3 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to shelter the Company from declining gas prices. Paramount's accounting policy recognizes these gains in the accounting years of related production. The amounts of deferred hedging gains that will be recognized in revenue by the Company in future years are as follows:

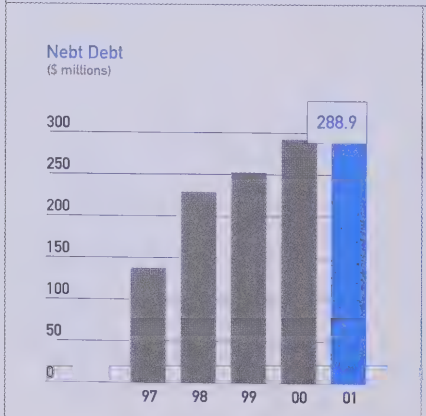
Deferred Revenue (thousands of dollars)	**Amount**
2002	$ 1,032
2003	395
Total deferred revenue	$ 1,427

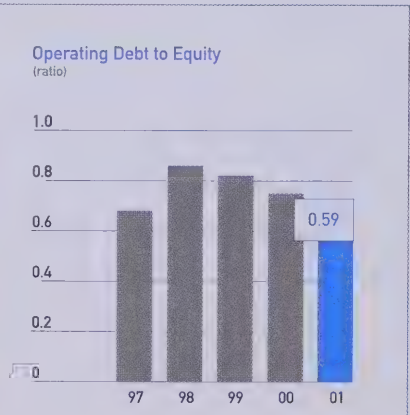
BANK DEBT, LIQUIDITY AND RISK MANAGEMENT

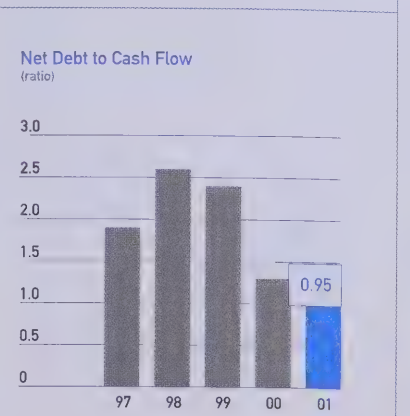
Paramount's debt and equity capital structure as at December 31, 2001, was as follows:

	AT COST			AT MARKET[1]		
(thousands of dollars, except per share)	Amount	%	$/Share[2]	Amount	%	$/Share[2]
Bank debt, net of working capital	$ 288,926	41	4.86	$ 288,926	21	4.86
Future income taxes	221,873	32	3.73	221,873	17	3.73
Common share equity	189,320	27	3.18	838,295	62	14.10
Total	$ 700,119	100	11.77	$ 1,349,094	100	22.69

(1) Close at December 31, 2001 - $14.10/share.
(2) At December 31, 2001 – 59,453,600 basic common shares outstanding.







The Company has an Extendible Revolving Term Credit Facility ("Credit Facility") with a syndicate of financial institutions in the amount of $330 million, including a $25 million working capital facility and a $305 million production facility. Available borrowings are limited by a borrowing base, established annually based on the value of petroleum and natural gas assets as determined by the lender. The loan is reviewed annually and may be requested by the bank to be repaid within one year in monthly installments determined by the syndicate. At December 31, 2001, $314.1 million was drawn under the credit facility.

Working capital liquidity is maintained by drawing from and repaying the unutilized credit facilities as needed. At December 31, 2001, Paramount had working capital of $27.7 million.

A key component of Paramount's capitalization is debt funding. Properly managed, debt funding enhances growth and profitability to shareholders without dilution or unnecessary risk. Historically, Paramount has utilized bank debt primarily for new plant development capital expenditures. As a result, the Company has maintained a weighted average net debt to cash flow ratio less than 2:1 over the past five years. The Company plans to continue utilizing debt financing and believes that a net debt to cash flow ratio of 2:1 is prudent in conjunction with other risk management strategies employed. As at December 31, 2001, all debt was subject to floating interest rates applicable to financial instruments known as bankers' acceptances that generally provide for a lower rate of interest than the alternative bank prime rate cost of borrowing.

Also of significant importance to the Company is the Canada/US exchange ratio, since a substantial percentage of the natural gas sales and crude oil sales of the Company are made into and priced effectively on US markets. Any improvement in the Canadian dollar relative to its US counterpart will have a negative impact on the wellhead price received for our production. To manage this risk, Paramount has entered into currency swap agreements that have fixed the exchange rates on US $27.8 million of future production revenue over the next three years at Cdn. $39.7 million. In addition the Company's US $20 million bank loan is also designated as a currency hedge.

As at December 31, 2001, the Company's issued share capital consisted of 59,453,600 common shares. Paramount instituted a "Normal Course Issuer Bid" to acquire a maximum of 5 percent of its issued and outstanding shares commencing September 1, 2001, and ending August 31, 2002. During 2001, no shares were purchased pursuant to the plan.

RISKS AND UNCERTAINTIES

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as by worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect Paramount's oil price.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount controls as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company minimizes these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount will ensure continued compliance with environmental legislation.

KYOTO PROTOCOL ON GREENHOUSE GAS EMISSIONS

Canada is signatory to an International Treaty to achieve a 6 percent reduction from 1990 greenhouse gas emission levels by 2008-2012, which represents approximately a 25 percent cut from current levels. At this time the Company does not know what final course of action the Canadian or United States governments will take in this regard and accordingly cannot measure the potential risk to our business.

2002 CASH FLOW FORECAST AND SENSITIVITY ANALYSIS

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise budgets as necessary to reflect the most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2002 cash flow using the following base assumptions:

a) 2002 Production

Natural gas	250 – 265 MMcf/d
Crude oil/liquids	2,500 – 3,000 Bbl/d

b) 2002 Average Prices

Natural gas	$ 2.50/Mcf
Crude oil/liquids (W.T.I.)	$ 19.50/Bbl

c) Cash Flow

$185 – $200 million

d) 2002 Net Capital Expenditures

$175 – $200 million

The following analysis assesses the estimated after-tax impact on cash flow with variations in production, price, interest and exchange rates:

Sensitivity (millions of dollars)	**Cash Flow**
Gas sales change of 10 MMcf/d	$ 5.6
Gas price change of $0.10/Mcf	$ 5.9
Oil and natural gas liquids sales change of 100 Bbl/d	$ 0.7
Oil and natural gas liquids price change of $1.00/Bbl (W.T.I.)	$ 1.0
Sensitivity to US/Canada exchange rate fluctuation of Cdn. $0.01	$ 1.0
Average interest rate change of 1%	$ 1.9

MANAGEMENT'S REPORT

The accompanying consolidated financial statements of Paramount Resources Ltd. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors is comprised of non-management directors. The Committee meets quarterly with management as well as the external auditors to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibility, and to review the Annual Report. The Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee and Management.



Clayton H. Riddell
President and Chairman of the Board



David J. Broshko, C.A.
Chief Financial Officer

March 21, 2002

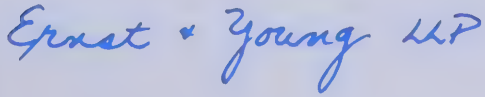
AUDITORS' REPORT

To the Shareholders of Paramount Resources Ltd.

We have audited the consolidated balance sheets of Paramount Resources Ltd. as at December 31, 2001 and 2000, and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000, and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Chartered Accountants

March 21, 2002
Calgary, Canada

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands of dollars)	2001	2000
ASSETS (note 5)		
Current Assets		
Cash	$ 740	$ 416
Short-term investments (market value: 2001 – $29,598; 2000 – $43,635)	13,932	25,189
Accounts receivable	72,356	109,493
Prepaid expenses	15,092	10,230
Deferred hedging loss (note 8)	17,638	–
	119,758	145,328
Property, Plant and Equipment (note 3)		
Petroleum and natural gas properties, at cost	1,440,105	1,178,921
Accumulated depletion and depreciation	(381,768)	(276,420)
	1,058,337	902,501
	$ 1,178,095	$ 1,047,829
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 92,084	$ 139,725
Bank loan (note 5)	314,148	310,521
Drilling rig indebtedness (note 4)	2,452	4,479
Provision for future site restoration and abandonment costs	8,955	6,555
Deferred revenue	1,427	2,587
Future income taxes (note 7)	221,873	165,708
	640,939	629,575
Commitments and Contingencies (notes 4, 8 and 10)		
Shareholders' Equity		
Share capital (note 6)		
Issued and outstanding		
59,453,600 common shares (2000 – 59,453,600 common shares)	189,320	189,320
Retained earnings	347,836	228,934
	537,156	418,254
	$ 1,178,095	$ 1,047,829

See accompanying notes to consolidated financial statements.

On behalf of the Board

Clayton H. Riddell
Director

G. B. Padley
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

Years ended December 31 (thousands of dollars except per share amounts)	2001	2000
Revenue		
Petroleum and natural gas sales	$ 528,373	$ 391,470
Royalties (net of ARTC)	(99,706)	(80,541)
	428,667	310,929
Expenses		
Operating	61,045	47,974
Interest	19,291	22,313
General and administrative	12,346	9,660
Geological and geophysical	10,646	6,784
Dry hole costs	8,944	7,019
Lease rentals	4,319	5,231
(Gain) loss on sales of property and equipment	1,537	(662)
Provision for future site restoration and abandonment costs	2,400	1,680
Depletion and depreciation	105,433	50,563
	225,961	150,562
Earnings before taxes	202,706	160,367
Income and other taxes (note 7)		
Current	25,000	–
Large corporations tax and other	2,729	2,305
Future income tax expenses	56,075	72,000
	83,804	74,305
Net earnings	118,902	86,062
Retained earnings, beginning of year	228,934	142,872
Retained earnings, end of year	$ 347,836	$ 228,934
Net earnings per common share (note 2)		
– basic	$ 2.00	$ 1.45
– diluted	$ 2.00	$ 1.45
Weighted average common shares outstanding (thousands)		
– basic	59,454	59,454
– diluted	59,527	59,454

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 (thousands of dollars except for per share amounts)	2001	2000
Operating activities		
Net earnings	$ 118,902	$ 86,062
Add (deduct) non-cash items		
Depletion and depreciation	105,433	50,563
(Gain) loss on sales of property and equipment	1,537	(662)
Provision for future site restoration and abandonment costs	2,400	1,680
Future income taxes	56,075	72,000
Add items not related to operating activities		
Dry hole costs	8,944	7,019
Geological and geophysical costs	10,646	6,784
Cash flow from operations	303,937	223,446
Decrease in deferred revenue	(1,160)	(1,235)
Change in non-cash operating working capital (note 9)	(17,677)	(4,024)
	285,100	218,187
Financing activities		
Bank loan	3,627	43,161
Drilling rig indebtedness	(2,027)	3,020
	1,600	46,181
Cash flow provided by operating and financing activities	286,700	264,368
Investing activities		
Property and equipment expenditures	266,172	250,142
Petroleum and natural gas property acquisitions	8,345	19,950
Geological and geophysical costs	10,646	6,784
Proceeds on sale of property and equipment	(2,857)	(14,205)
Change in non-cash investing working capital (note 9)	4,070	1,294
Cash flow used in investing activities	286,376	263,965
Increase in cash	324	403
Cash, Beginning of Year	416	13
Cash, end of year	$ 740	$ 416
Cash flow from operations per common share (note 2)		
– basic	$ 5.11	$ 3.76
– diluted	$ 5.11	$ 3.76
Weighted average common shares outstanding (thousands)		
– basic	59,454	59,454
– diluted	59,527	59,454

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(all tabular amounts expressed in thousands of dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. (the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Paramount Resources Ltd. and its wholly owned subsidiaries Paramount Resources (US) Inc. and 586319 Alberta Ltd.

(B) JOINT VENTURES

The Company accounts for its interest in a drilling company, pipeline company and engineering company where it exercises joint control using proportionate consolidation whereby its pro-rata share of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company's financial statements.

(C) SHORT-TERM INVESTMENTS

Investments in marketable securities are carried at the lower of cost and market value.

(D) INVENTORY

Inventory of materials and equipment is carried at the lower of cost, determined on a first-in-first-out basis, and net realizable value and is included in petroleum and natural gas properties.

Natural gas in storage is carried at the lower of cost and net realizable value. Cost includes all amounts incurred to produce or purchase the related gas, transportation to the storage facility and the cost of storage. At December 31, 2001, there was no natural gas inventory.

(E) PETROLEUM AND NATURAL GAS PROPERTIES

The Company follows the "Successful Efforts" Method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net cost of unproductive wells, abandoned wells and surrendered leases is charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of properties and equipment.

Depletion and depreciation of petroleum and natural gas properties including well development expenditures, production equipment, gas plants and gathering systems are provided on the unit-of-production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of other equipment is provided on a declining balance method at rates varying from 20 to 30 percent.

The net amount at which petroleum and natural gas costs on a property or project are carried is subject to a cost-recovery test. The carrying values of capital assets, including the cost of acquiring proven and probable reserves, are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors. Future events could result in material changes to the carrying values recognized in the financial statements.

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(F) FUTURE SITE RESTORATION AND ABANDONMENT COSTS

Estimated future site restoration and abandonment costs are provided for in the financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon current regulations and economic circumstances at year end. Actual site restoration costs are deducted from the provision in the year incurred.

(G) FOREIGN CURRENCY TRANSLATION

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in US dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred except for unrealized gains or losses on translation of long-term bank loans, which are deferred and amortized on a straight-line basis over the expected minimum repayment period.

(H) FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instrument contracts to manage its exposure to petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rate fluctuations. Gains or losses from foreign exchange and commodity hedge contracts are recognized in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred. The fair values of these contracts are not reflected in the financial statements.

(I) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment and for site restoration and reclamation are based on estimates of reserves and future costs. By their nature, these estimates and those related to the future cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

(J) FLOW-THROUGH SHARES

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. Under this type of financing arrangement, shares are issued at a fixed price and the proceeds used to fund exploration and development activities within a defined time period. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. To recognize the foregone tax benefits to the Company, shares are recorded net of the estimated tax benefit renounced to investors with a corresponding future tax liability recorded at the later of the date the qualifying expenditures are renounced and the date they are incurred.

(K) INCOME TAXES

The Company follows the liability method of tax accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

(L) STOCK OPTION PLAN / SHARE APPRECIATION RIGHTS PLAN ("SARPs")

The Company has a stock-based compensation plan as described in Note 6. In 2001, the Company adopted the new Canadian Institute of Chartered Accountants Standard on Stock-Based Compensation on a prospective basis. Under this new standard, the Company's stock options and SARPs, which can be settled in cash at the discretion of the employee, are accounted for at an amount equal to the difference between the exercise price and the fair value at the date of grant. The awards are remeasured at each reporting date, resulting in a liability and corresponding compensation expense being recognized. The impact of the adoption of the new standard on the current and prior years is not material.

2. CHANGE IN ACCOUNTING FOR PER SHARE AMOUNTS

Effective January 1, 2001, the Company adopted the new Canadian Institute of Chartered Accountants recommendations for determining per share amounts. The new standard utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding in the money options and warrants are used to purchase shares of the Company at their average market price for the period. The new method had no impact on the 2000 diluted per share amounts. Prior to the adoption of the new recommendation, diluted per share amounts were determined using the imputed earnings method.

3. PROPERTY, PLANT AND EQUIPMENT

	2001		2000	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties	$ 919,667	$ 188,826	$ 752,230	$ 110,346
Gas plants, gathering systems and production equipment	507,976	185,527	415,395	160,027
Other	12,462	7,415	11,296	6,047
	$ 1,440,105	$ 381,768	$ 1,178,921	$ 276,420
Net book value	$ 1,058,337		$ 902,501	

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $402 million (2000 – $448 million) are excluded from capitalized costs subject to depletion.

4. JOINT VENTURES

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of its joint ventures as follows:

	2001	2000
Assets		
Current assets	$ 1,983	$ 204
Property and equipment	6,822	4,926
	$ 8,805	$ 5,130
Liabilities and equity		
Current liabilities	$ 6,908	$ 752
Bank loan	3,541	4,479
Deficit	(1,644)	(101)
	$ 8,805	$ 5,130
Revenues	$ 1,842	$ 368
Net loss	$ (1,542)	$ (206)

Wilson Drilling Ltd. had a reducing term loan facility available to a maximum of $8.6 million at December 31, 2001. The loan is repayable in equal quarterly installments of $500,000 to June 2005. As at December 31, 2001, this facility had an effective interest rate of 5.25 percent. The Company has provided a guarantee as collateral for the facility. Earnings attributed to services provided to the Company have been eliminated from the accompanying consolidated statement of earnings.

5. BANK LOAN

The Company has an Extendible Revolving Term Credit Facility ("Credit Facility") with a syndicate of financial institutions in the amount of $330 million, including a $25 million working capital facility and a $305 million production facility. Available borrowings are limited by a borrowing base, established annually based on the value of petroleum and natural gas assets as determined by the lenders. The borrowing base as at January 2002 was $330 million (2000 – $315 million).

The Credit Facility is reviewed annually by April 30th of each year and may be requested by the bank to be repaid within one year in monthly installments to be determined by the syndicate. The banking syndicate has indicated that no principal payments are anticipated. Accordingly, the bank loan has been classified as long-term.

As at December 31, the following amounts were drawn under this facility:

	2001	2000
Bankers' acceptances – 30-day average rate of 5.25% (2000 – 7.07%)	$ 282,234	$ 280,379
LIBOR advances (US $20,000,000) – fixed rate	31,914	30,142
	$ 314,148	$ 310,521

The Company has provided a first floating charge on all assets in the amount of $500 million and a general assignment pursuant to a general security agreement.

The Company has letters of credit totaling $11.4 million outstanding with a Canadian Chartered Bank.

6. SHARE CAPITAL

AUTHORIZED CAPITAL

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

ISSUED CAPITAL

Common Shares	Number	Consideration
Balance December 31, 1999	59,453,600	$ 199,320
Tax benefits relating to qualifying expenditures renounced to flow-through shareholders	–	(10,000)
Balance December 31, 2000 and 2001	59,453,600	$ 189,320

STOCK OPTION PLAN/SHARE APPRECIATION RIGHTS PLAN

As at December 31, 2001, 2.4 million stock options were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 2.2 million shares are outstanding, exercisable to January 31, 2005, at prices ranging from $11.00 to $16.50 per share. During 2001, 329,500 SARPs were exercised at a cost of $1.7 million (2000 – 295,750 SARPs – $2.0 million), which amount is recorded to general and administrative expenses.

SARPs/Stock options	2001		2000	
	Average grant price	Rights/ options	Average grant price	Rights
Balance, beginning of year	$ 12.72	1,184,500	$ 11.63	1,104,250
Granted	14.33	1,694,500	13.00	463,000
Exercised	14.93	(329,500)	16.12	(295,750)
Cancelled	14.16	(376,000)	12.32	(87,000)
Balance, end of year	$ 14.08	2,173,500	$ 12.72	1,184,500
SARPs/Options exercisable, end of year	$ 13.23	213,500	$ 11.31	414,000

During 2001, the Company replaced the Share Appreciation Rights Plan with an employee stock option plan. Share appreciation rights previously held by employees will be grandfathered until their expiry on January 31, 2004 and will be capped at a price of $14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and $14.50, which difference will be charged to general and administrative expenses. At December 31, 2001, 479,000 SARPs remained outstanding.

The following summarizes information about stock options/SARPs outstanding at December 31, 2001:

Year of grant	Number outstanding at December 31, 2001	Weighted average remaining contractual life (years)	Weighted average exercise price/share	Number exercisable at December 31, 2001	Weighted average exercise price/share
2001	1,694,500	4	$ 14.33	–	$ 14.33
2000	267,500	3	$ 13.00	83,000	$ 13.00
1999	119,500	3	$ 14.00	51,000	$ 14.00
1998	68,000	2	$ 11.56	55,500	$ 11.46
1997	24,000	1	$ 16.50	24,000	$ 16.50
	2,173,500		$ 14.08	213,500	

7. INCOME TAXES

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to income before taxes as follows:

	2001	2000
Corporate tax rate	43.18%	44.62%
Calculated income tax expense	$ 87,528	$ 71,555
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	41,394	33,007
Federal resource allowance	(45,215)	(36,467)
Provincial income tax rate adjustment	(8,842)	–
Large Corporation Tax and other	2,729	2,305
Other	6,210	3,905
Income tax expense	$ 83,804	$ 74,305

COMPONENTS OF FUTURE INCOME TAXES

The net future tax liability comprises:	2001
Differences between tax base and reported amounts of depreciable assets	$ 217,617
Share issue costs	(190)
Provision for future site restoration	(2,867)
Deferred hedging loss	5,648
Other	1,665
	$ 221,873

As at December 31, 2001, the Company has tax pools of approximately $562.1 million (2000 – $497.4 million) available for deduction against future taxable income.

8. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the Consolidated Balance Sheet are comprised of cash, short-term investments, accounts receivable, current liabilities, bank loan and drilling rig indebtedness.

(A) FOREIGN EXCHANGE HEDGES

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of US $27.8 million for Cdn. $39.7 million over the next three years at Cdn. $1.4264. The US $/Cdn. $ closing exchange rate was 1.5928 as at December 31, 2001 (2000 – 1.5002).

	US Dollars	Weighted average exchange rate
2002	$ 22,920	1.4275
2003	4,570	1.4211
2004	360	1.4206
	$ 27,850	1.4264

At December 31, 2001, the estimated fair value based on the Company's assessment of available market information was $44.3 million.

(B) NATURAL GAS COMMODITY PRICE HEDGES

The Company has entered into financial forward sales arrangements on 115 million cubic feet per day ("MMcf/d") of natural gas as follows:

	Price	Term
AECO		
80,000 GJ/d	$ 4.3825	January 1, 2002 – December 31, 2002
10,000 GJ/d	$ 3.6850	January 1, 2002 – December 31, 2002
NYMEX		
5 MMcf/d	US $ 3.63	September 1, 2001 – October 31, 2002
10 MMcf/d	US $ 3.66	September 1, 2001 – October 31, 2002
10 MMcf/d	US $ 3.67	September 1, 2001 – October 31, 2002

The pre-tax unrealized gain on these financial contracts at December 31, 2001, totaled $35.4 million. The AECO price at year-end was $3.72/Mcf and the NYMEX price was U.S. $2.53/Mcf.

During 2001, $15.8 million of net gains related to natural gas commodity hedging contracts (2000 – $5.1 million net losses) are included in natural gas sales revenue.

(C) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based, thus, carrying values which approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

The fair values of other financial instruments, including cash, accounts receivable, and accounts payable and accrued liabilities and long-term debt, approximate their carrying values due to the short-term maturity of those instruments.

9. CHANGE IN NON-CASH WORKING CAPITAL

	2001	2000
Change in non-cash working capital:		
Short-term investments	$ 11,257	$ (21,650)
Accounts receivable	37,137	(69,923)
Prepaid expenses	(4,862)	(1,532)
Deferred hedging costs	(17,638)	–
Accounts payable and accrued liabilities	(47,641)	87,787
	$ (21,747)	$ (5,318)
Operating activities	$ (17,677)	$ (4,024)
Investing activities	(4,070)	(1,294)
Financing activities	–	–
Change attributable to operating activities	$ (21,747)	$ (5,318)

Amounts paid during the year related to interest and capital taxes were as follows:

	2001	2000
Interest paid	$ 19,135	$ 22,080
Capital taxes paid	$ 2,729	$ 2,305

10. CONTINGENCIES

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial postion.

11. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current financial statement presentation.

12. SUBSEQUENT EVENTS

Subsequent to December 31, 2001, Paramount Resources Ltd. entered into a Memorandum of Agreement with the Province of Alberta and Conoco Canada Resources Ltd., effective May 1, 2000.

The Memorandum of Agreement provides, inter alia, for compensation of $85 million to the Surmont Gas Producers by the Alberta Crown as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, lands and leases affected by the shut-in order of May 1, 2000. Paramount is entitled to slightly over half of the compensation amount.

The Memorandum of Agreement remains conditional on the Surmont Gas Producers and Conoco entering into an agreement governing their relationship relative to Conoco's commercial production of the bitumen resource. All parties must also agree on what will be required for the shut-in gas production to resume and, in this context, must reach consensus on defining the parameters of a technical solution acceptable to all.

The financial statement impact will be recorded in the period in which the benefit is realized.

ANNUAL INFORMATION FORM

INCORPORATION

Paramount Resources Ltd. ("Paramount" or the "Company") was incorporated under the laws of the Province of Alberta on February 14, 1978. The Company commenced operations as a public company listed on the Alberta Stock Exchange on December 18, 1978, with a successful Initial Public Offering that raised $4.7 million and a share exchange with a private company, Paramount Oil & Gas Ltd., for certain crude oil and natural gas assets with book value of $341,000.

On November 30, 1984, Paramount was listed on The Toronto Stock Exchange (TSE). Paramount was added to the TSE 300 Composite Index (Subgroup 3.2 Oil & Gas Producers) and the TSE 200 Index effective January 16, 1998.

The head and principal office of the Company is located at Suite 4700, 888 Third Street S.W., Calgary, Alberta T2P 5C5.

MANAGEMENT OF THE COMPANY

The management of the Company is provided by seven officers, three of whom currently serve as directors. There are eight non-management directors to complete the Board of Directors. The names, municipality of residence, position with Paramount and principal occupation of each of the officers and directors can be found in the Management Information and Proxy Circular dated March 22, 2002.

The term of office for each director of the Company is from the date of the annual meeting at which the director is elected or appointed until the annual meeting next following or until a successor is elected or appointed. The current Board of Directors was nominated and elected at the Annual Meeting of the Shareholders held on June 14, 2001. The Board of Directors has an Audit Committee which consists of Messrs. Padley, Roy and MacInnes; a Compensation Committee which consists of Messrs. C. H. Riddell, Roy and Wylie; and an Environmental Committee which consists of Messrs. MacInnes, Roy and Wylie.

As at December 31, 2001, the directors and officers of the Company as a group beneficially owned 32,032,723 common shares, representing 53.88 percent of the 59,453,600 issued and outstanding common shares of Paramount.

The 2002 Annual General Meeting will be held on June 20, 2002, in Calgary, Alberta.

DESCRIPTION AND DEVELOPMENT OF BUSINESS

Paramount is a Canadian natural resource company involved in the exploration, development and production of petroleum and natural gas, primarily in Alberta but also in British Columbia, Saskatchewan, the Northwest Territories, California and Wyoming. In 2001, sales of natural gas accounted for approximately 91 percent of the Company's total production.

The Company's ongoing exploration, development and production activities are designed to establish new reserves of oil and natural gas and to increase the productive capacity of existing fields. In order to optimize its net capacity and control costs, the Company increases ownership and throughput in existing plants as economic opportunities arise and occasionally disposes of lower working interest properties. Paramount strives to maintain a balanced portfolio of opportunities, increasing its working interest in low to medium risk projects and entering into joint venture arrangements on select high risk/high return exploration prospects.

Paramount also participates in the petroleum and natural gas industry through the focused acquisition of petroleum and natural gas assets within established core areas. This acquisition strategy focuses on long-term value including assets which will increase Paramount's current working interest. To take advantage of opportunities as they arise, the Company maintains a strong balance sheet, which allows such acquisitions to be financed.

At December 31, 2001, approximately 82 percent of Paramount's proved and probable natural gas reserves were located in Alberta with the balance in British Columbia and the Northwest Territories. Oil and natural gas liquids reserves are 92 percent located in Alberta, with the remainder in Saskatchewan, British Columbia and the Northwest Territories. In 2001, Paramount operated 89 percent of its producing natural gas wells and approximately 92 percent of its producing crude oil and natural gas liquids wells.

In addition to the historical focus on shallow gas in Northeast Alberta, Paramount has established core areas of production in Central Alberta, Northwest Alberta and the Northwest Territories. Paramount is continuing to explore actively for petroleum and natural gas reserves in Central and Northwest Alberta, Northeast British Columbia, Southeast Saskatchewan, Northwest Territories, California and Wyoming. The Company has also established opportunities for heavy oil exploration and development in Northeast Alberta. The development of new core areas ensures adequate supply for existing gas markets and contracts, and is accelerated within the limits of the Company's cash resources when markets are sufficient to support additional supply.

CAPITAL TRANSACTIONS

Since inception, the Company has raised share capital in public markets on four occasions. In addition, the shares of Paramount have split twice on a three-for-one basis. As at December 31, 2001, the Company had 59,453,600 shares outstanding with an indicated market capitalization of $838 million based upon the December 31, 2001, $14.10 per share closing price on the TSE. Following is a summary of capital transactions the Company has completed in the past five years:

1. On October 8, 1999, Paramount issued 2.5 million common shares at an average price of $21.87 per share pursuant to a private placement flow-through share offering for gross proceeds of $54.7 million. Proceeds from the issue were used to fund the 1999-2000 capital expenditure program.
2. On November 13, 1998, Paramount issued 3.0 million common shares at a price of $15.00 per share for gross proceeds of $45.0 million pursuant to a prospectus dated November 4, 1998. Proceeds were initially used to reduce bank indebtedness.
3. On November 4, 1997, Paramount issued 4.0 million common shares at $16.50 per share pursuant to a prospectus dated November 4, 1997.
4. On June 4, 1997, Paramount's common shares were split on a three-for-one basis resulting in 49,203,600 issued and outstanding common shares.

COMPETITIVE CONDITIONS

The petroleum and natural gas industry is highly competitive. Paramount competes with numerous other participants in the search for and acquisition of crude oil and natural gas properties and in the marketing of these commodities. Successful reserve replacement in the future will depend not only on the further development of present properties, but also on the ability to select and acquire suitable prospects for exploratory drilling and development.

Paramount has firm service for most of its natural gas production as opposed to interruptible allocations on pipeline systems. The Company closely monitors the daily production from all of its plants ensuring that contractual obligations will be met. Balancing contractual commitments, natural gas sales are directed to those markets where the Company believes prices will be best.

RECENT DEVELOPMENTS

Late in 1998, Gulf Canada Resources Ltd. submitted an application to the Alberta Energy and Utilities Board ("AEUB") requesting that the AEUB issue an order shutting in 183 wells located on and in the vicinity of its bitumen holdings in the Surmont area of northeast Alberta. The AEUB held a public hearing on this application which ran from April through September 1999. Paramount, as a member of the Surmont Gas Producers Group, was an active opponent of this application at the hearing.

On March 30, 2000, the AEUB issued "EUB Decision 2000-22" and a Board Order dated April 3, 2000, ordering the shut-in of 146 of the 183 wells and suspending the rights of natural gas leaseholders and producers to produce natural gas from the Wabiskaw and McMurray formations effective May 1, 2000. Paramount is the operator of 65 of these wells, 41 of which are currently capable of economic natural gas production from the Wabiskaw/McMurray at varying rates. The approximate average shut-in volume from these Paramount-operated producing wells is currently 20.7 MMcf/d before deduction of the Crown royalty share. In addition to the Paramount-operated wells, Paramount has an interest in 12 other wells subject to the Board Order. Paramount's share of shut-in production from these wells averages 1.3 MMcf/d before deduction of Crown royalties.

On February 28, 2002, Paramount Resources Ltd. entered into a Memorandum of Agreement with the Province of Alberta and Conoco Canada Resources Ltd. ("Conoco"), effective May 1, 2000. The Memorandum of Agreement provides, inter alia, for compensation of $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of Crown royalty relief as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, lands and leases affected by the shut-in order of May 1, 2000. Paramount is entitled to slightly over half of the compensation amount.

The Memorandum of Agreement remains conditional on the Surmont Gas Producers and Conoco entering into an agreement governing their relationship relative to Conoco's commercial production of the bitumen resource. All parties must also agree on what will be required for the shut-in gas production to resume and, in this context, must reach consensus on defining the parameters of a technical solution acceptable to all.

ENVIRONMENTAL PROTECTION

Paramount has in place an Environmental Committee of the Board of Directors composed of three non-management directors of the Company. The tenet of the Company's Environmental Policy is as follows:

Paramount Resources Ltd. "Paramount" is committed to protecting the environment, to maintaining public health and safety, and to compliance with all applicable environmental laws, regulations and standards. Paramount will do all that it reasonably can to ensure that sound environmental practices are followed in all of its operations and activities.

The Committee is guided by a specific set of principles to ensure that this policy is supported. These principles apply to all employees of Paramount and are designed to make certain that all applicable environmental laws, regulations and standards are complied with. The Company monitors all activities and makes reasonable efforts to ensure that companies who provide services to Paramount will operate in a manner consistent with its environmental policy.

In recognition of its Environmental and Safety Policies and to demonstrate continual improvement in its performance, Paramount has been awarded the Canadian Association of Petroleum Producers' ("CAPP") Gold Level Certificate for Stewardship participation, the Silver Champion Level Reporter Recognition level from Canada's Climate Change Voluntary Challenge and Registry Inc. and the Alberta Human Resources and Employment Certificate of Recognition for its safety management program. Paramount is also registered in the Workers' Compensation Board 'Partners in Injury Reduction' ("PIR") program. Paramount has systems and procedures in place to manage its safety and environmental affairs effectively and to meet regulatory compliance.

HUMAN RESOURCES

At January 1, 2002, Paramount had 108 full-time head office employees and 80 full-time employees at field locations. The Company's compensation of full-time employees includes a combination of salary, benefits and participation in either a stock option/share appreciation rights plan or a company-assisted share purchase savings plan. Shares under the savings plan are purchased in the marketplace by the plan trustee.

LAND

The following table sets forth Paramount's land position at December 31, 2001. The Company's holdings total 6,575,384 gross (4,983,561 net) acres. Approximately 75 percent of the Company's gross land holdings are considered undeveloped, and approximately 44 percent of the undeveloped land is located in Alberta.

	2001		2000		1999		1998		1997	
(thousands of acres)	Gross[1]	Net[2]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Undeveloped land										
Alberta	2,138	1,524	2,100	1,475	1,950	1,388	1,789	1,178	1,505	920
British Columbia	248	163	178	101	191	105	138	73	99	44
Saskatchewan	6	1	7	1	199	39	238	44	438	145
Northwest Territories	845	580	795	523	494	221	509	220	309	114
Other	1,664	1,497	1,664	1,497	–	–	–	–	–	–
Subtotal	4,901	3,765	4,744	3,597	2,834	1,753	2,674	1,515	2,351	1,223
Acreage assigned reserves										
Alberta	1,592	1,170	1,408	1,008	1,446	1,027	1,280	866	1,091	739
British Columbia	8	3	3	1	17	9	16	9	16	8
Saskatchewan	1	0*	–	–	16	4	15	40	51	22
Northwest Territories	74	45	61	42	60	41	45	3	46	40
Subtotal	1,675	1,218	1,472	1,051	1,539	1,081	1,356	918	1,204	809
Total Acres	6,575	4,984	6,216	4,648	4,373	2,834	4,030	2,433	3,555	2,032

*Net acreage assigned reserves in Saskatchewan less than 1,000 acres

(1) "Gross" acres means the total acreage in which Paramount has a working interest.

(2) "Net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

DRILLING HISTORY

The following table summarizes the results of Paramount's drilling activity for each of the last five fiscal years. The working interest in certain of these wells may change after payout.

	2001		2000		1999		1998		1997	
	Gross[1]	Net[2]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells[3]										
Gas	101	84.4	37	27.0	50	41.9	50	36.3	58	43.8
Oil	7	6.1	9	5.8	8	4.0	10	3.9	11	2.2
Standing/service	–	–	2	1.3	1	0.5	5	3.8	20	7.1
Dry	4	3.5	2	2.0	3	2.0	4	3.5	4	3.0
Subtotal	112	94.0	50	36.1	62	48.4	69	47.5	93	56.1
Exploration Wells										
Gas	66	52.6	88	71.6	42	31.3	59	38.1	23	10.1
Oil	5	4.2	2	0.5	1	0.3	13	2.9	17	3.2
Standing/service	1	0.5	–	–	2	0.4	6	3.6	8	2.5
Dry	12	7.4	23	20.5	7	5.7	25	11.8	6	1.5
Subtotal	84	64.7	113	92.6	52	37.7	103	56.4	54	17.3
Total Wells	196	158.7	163	128.7	114	86.1	172	103.9	147	73.4

(1) "Gross" wells means the number of wells in which Paramount has a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

(3) "Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool that is partly discovered.

(4) "Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.

OIL AND NATURAL GAS WELLS

As at December 31, 2001, Paramount had an interest in 1,995 gross (1,457.2 net) producing and non-producing oil and natural gas wells as follows:

	Producing[1]		Non-producing[2]	
As at December 31, 2001	Gross	Net	Gross	Net
Natural gas wells				
Alberta	1,145	855.5	664	492.6
British Columbia	4	1.5	5	3.0
Saskatchewan	–	–	1	0.3
Northwest Territories	6	1.5	22	14.7
Subtotal	1,155	858.5	692	510.6
Crude oil wells				
Alberta	86	51.3	50	29.9
British Columbia	–	–	–	–
Saskatchewan	4	1.0	1	0.3
Northwest Territories	–	–	7	5.6
Subtotal	90	52.3	58	35.8
Total	1,245	910.8	750	546.4

(1) "Non-producing" wells are wells that Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.
(2) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be convertible to a working interest after payout.
(3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

RESERVES

Paramount's assigned reserves of crude oil, natural gas liquids and natural gas are located exclusively in Canada. For 2001, all reserves were determined through independent engineering evaluations completed by McDaniel & Associates Consultants Ltd. ("McDaniel"), a firm of independent petroleum consultants. Their report was prepared effective January 1, 2002, and dated January 14, 2002.

The following table details Paramount's working interest share of reserves, net reserves after royalties, and present worth values as at December 31, 2001:

	Gross (before royalties,	Net (after royalties,	Present Worth Value (before tax, $ millions)			
December 31, 2001, Reserve Summary	Bcf)	Bcf)	0%	10%	15%	20%
Natural gas reserves						
Proved producing	298.9	234.8	671.1	519.0	467.8	426.8
Proved shut-in	114.1	96.0	252.6	148.2	123.7	106.5
Proved undeveloped	24.7	22.6	60.1	28.6	22.2	18.1
Total proved	437.7	353.4	983.8	695.8	613.8	551.4
Probable additional	126.0	103.6	336.6	174.0	137.0	111.9
50% reduction for risked probable reserves	(63.0)	(51.8)	(168.3)	(87.0)	(68.5)	(55.9)
Risked probable additional	63.0	51.8	168.3	87.0	68.5	56.0
Total risked natural gas reserves	500.7	405.2	1,152.1	782.8	682.3	607.4
Crude oil and natural gas liquids reserves						
Proved producing	5,063	4,037	80.1	54.2	47.3	42.2
Proved shut-in	948	749	20.3	10.7	8.9	7.9
Proved undeveloped	328	309	7.3	4.5	3.7	3.0
Total proved	6,339	5,095	107.7	69.4	59.9	53.1
Probable additional	1,628	1,411	28.4	14.9	11.7	9.5
50% reduction for risked probable reserves	(814)	(705)	(14.2)	(7.4)	(5.8)	(4.7)
Risked probable additional	814	706	14.2	7.5	5.9	4.8
Total risked crude oil and natural gas liquids reserves	7,153	5,801	121.9	76.9	65.8	57.9

The Company's five-year summary of reserves is outlined in the following tables. Probable reserves reported in the tables below have been arbitrarily reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)	2001	2000	1999	1998	1997
Gross before royalties					
Proved producing	298.9	338.5	370.9	412.8	357.0
Proved non-producing, proved undeveloped	138.8	179.6	223.8	194.5	124.7
Total proved	437.7	518.1	594.7	607.3	481.7
Probable additional	126.0	139.3	155.1	180.9	155.1
Total proved and probable	563.7	657.4	749.8	788.2	636.8
50% reduction for risked probable reserves	(63.0)	(69.6)	(77.5)	(90.5)	(77.6)
Total risked reserves	500.7	587.8	672.3	697.7	559.2
Net after royalties					
Proved producing	234.8	265.3	284.0	318.8	283.3
Proved non-producing, proved undeveloped	118.6	155.1	192.7	173.4	111.9
Total proved	353.4	420.4	476.7	492.2	395.2
Probable additional	103.6	113.4	127.7	150.3	127.2
Total proved and probable	457.0	533.8	604.4	642.5	522.4
50% reduction for risked probable reserves	(51.8)	(56.7)	(63.8)	(75.2)	(63.6)
Total risked reserves	405.2	477.1	540.6	567.3	458.8
Crude oil & liquids reserves (MBbl)					
Gross before royalties					
Proved producing	5,063.0	4,290.0	3,231.1	5,018.0	4,912.0
Proved non-producing, proved undeveloped	1,276.0	419.0	3,032.8	2,877.0	3,474.0
Total proved	6,339.0	4,709.0	6,263.9	7,895.0	8,386.0
Probable additional	1,628.0	1,271.0	2,616.0	3,735.0	5,053.9
Total proved and probable	7,967.0	5,980.0	8,879.9	11,630.0	13,439.9
50% reduction for risked probable reserves	(814.0)	(635.5)	(1,308.0)	(1,867.5)	(2,527.0)
Total risked reserves	7,153.0	5,344.5	7,571.9	9,762.5	10,912.9
Net after royalties					
Proved producing	4,037.0	3,325.0	2,569.3	4,102.0	3,785.0
Proved non-producing, proved undeveloped	1,058.0	292.0	2,303.7	2,109.0	2,566.2
Total proved	5,095.0	3,617.0	4,873.0	6,211.0	6,351.2
Probable additional	1,411.0	1,106.0	2,134.6	3,053.0	3,858.5
Total proved and probable	6,506.0	4,723.0	7,007.6	9,264.0	10,209.7
50% reduction for risked probable reserves	(706.0)	(553.0)	(1,067.3)	(1,526.5)	(1,929.3)
Total risked reserves	5,800.0	4,170.0	5,940.3	7,737.5	8,280.4

RESERVE RECONCILIATION

The table below sets forth Paramount's reconciliation of gross proved and probable reserves from January 1, 2001, to January 1, 2002, using escalated prices and costs. The probable reserves have been reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)	Proved	Probable	Total
Risk discounted balance at January 1, 2001	518.1	69.7	587.8
Revisions of previous estimates	(33.1)	(24.5)	(57.6)
Extensions and discoveries	29.9	10.2	40.1
Acquisitions of gas in place	4.8	1.1	5.9
Dispositions of gas in place	–	–	–
Production estimate	(82.0)	–	(82.0)
50% reduction for risked probable reserves	–	6.5	6.5
Balance at January 1, 2002	437.7	63.0	500.7

Crude oil and liquids (MBbl)	**Proved**	**Probable**	**Total**
Risk discounted balance at January 1, 2001	4,709.0	635.5	5,344.5
Revisions of previous estimates	433.0	(238.0)	195.0
Extensions and discoveries	1,171.0	397.0	1,568.0
Acquisitions of crude oil/liquids in place	776.0	198.0	974.0
Dispositions of crude oil/liquids in place	–	–	–
Production estimate	(750.0)	–	(750.0)
50% reduction for risked probable reserves	–	(178.5)	(178.5)
Balance at January 1, 2002	6,339.0	814.0	7,153.0

The following table sets forth Paramount's reconciliation of gross natural gas reserves for each of the past five years:

Natural gas reserves (Bcf)	**2001**	**2000**	**1999**	**1998**	**1997**
Opening balance	587.8	672.3	697.8	559.2	411.1
Revisions of previous estimates	(57.6)	(85.1)	(96.3)	71.0	45.2
Extensions and discoveries	40.1	59.8	99.4	100.1	31.3
Acquisitions of gas in place	5.9	29.0	38.8	64.9	150.5
Dispositions of gas in place	–	(14.0)	–	(16.9)	(19.6)
Production estimate	(82.0)	(82.0)	(80.3)	(67.7)	(47.0)
50% reduction for risked probable reserves	6.5	7.8	12.9	(12.8)	(12.3)
Closing balance	500.7	587.8	672.3	697.8	559.2

The following definitions form the basis of classification for reserves presented in the McDaniel report:

1. *"Proved Reserves" are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.*

 i) *Proved Producing Reserves*
 Those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

 ii) *Proved Non-Producing Reserves*
 Those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditures to produce.

 iii) *Proved Undeveloped Reserves*
 Those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

2. *"Probable Additional Reserves" are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.*

3. *"Gross Reserves" are defined as the reserves owned before deduction of any royalties.*

4. *"Net Reserves" are defined as the gross reserves of the properties in which an interest is held, less all royalties and interests owned by others.*

MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties, for each of the last five fiscal years:

Natural Gas (MMcf/d)	2001	2000	1999	1998	1997
Northeast Alberta – East Side					
Bohn Lake	3.4	3.8	4.8	–	–
Chard	2.4	2.7	3.5	4.2	3.6
Clyde	3.0	2.8	2.2	2.5	1.1
Cold Lake	11.9	14.4	17.1	13.3	–
Corner	15.5	15.1	20.3	25.2	24.1
Kettle River	5.5	10.9	24.9	24.8	21.2
Leismer	11.2	8.0	3.5	3.1	3.7
Quigley	3.0	5.0	10.1	11.6	6.8
Thornbury	4.9	6.1	6.9	6.8	–
Winefred	5.5	6.9	7.1	6.5	–
Other	0.8	1.1	4.8	4.8	5.2
Subtotal	67.1	76.8	105.2	102.8	65.7
Northeast Alberta – West Side					
East Legend	4.7	4.5	–	–	–
East Liege	3.1	4.2	5.7	–	–
Legend	17.3	14.0	14.1	14.6	9.7
North Liege	3.3	3.8	4.6	6.3	8.3
South Liege	5.2	5.8	9.0	9.3	1.1
Saleski	4.1	4.6	5.7	6.7	7.4
Teepee Creek	2.7	5.3	9.3	10.7	6.8
Other	1.2	–	–	–	–
Subtotal	41.6	42.2	48.4	47.6	33.3
Central Alberta					
Fox Creek	2.5	1.5	–	–	–
Kaybob	18.8	18.5	9.8	6.5	8.3
Kaybob North	30.7	31.0	24.5	13.2	7.3
Pine Creek	7.5	7.3	4.9	–	–
Puskwa	1.6	3.1	–	–	–
Other	7.3	2.3	8.4	7.4	3.1
Subtotal	68.4	63.7	47.6	27.1	18.7
Northwest Alberta					
Assumption	2.7	2.8	–	–	–
Bistcho Lake	9.5	10.7	10.0	8.0	6.6
Negus East	6.7	4.8	–	–	–
Negus West	3.6	1.9	–	–	–
Pedigree	6.1	5.1	3.3	–	–
Other	0.6	0.8	0.7	–	–
Subtotal	29.2	26.1	14.0	8.0	6.6
Liard Basin – Northeast British Columbia/Northwest Territories					
Maxhamish/Liard	5.2	4.6	–	–	–
Liard Non-Op	2.5	0.8	–	–	–
Other	1.6	–	–	–	–
Subtotal	9.3	5.4	–	–	–
Non-Core	9.4	5.8	4.8	18.0	24.3
Total	225.0	220.0	220.0	203.5	148.6

MAJOR PRODUCING PROPERTIES (CONTINUED)

Crude Oil and Liquids (Bbl/d)	2001	2000	1999	1998	1997
Alberta					
Kaybob	171	119	89	84	98
Kaybob North	711	498	218	253	48
Kaybob West	576	274	297	323	378
Pine Creek	265	213	152	138	–
Other	132	154	83	223	187
Subtotal	1,855	1,258	839	1,021	711
Saskatchewan					
Hardy	130	218	–	–	–
Midale	–	–	795	790	561
Other	–	–	57	–	55
Subtotal	130	218	852	790	616
Northwest Territories	21	95	–	–	–
Non-Op	159	–	163	177	65
Total	2,165	1,571	1,854	1,988	1,392

The following is a summary of Paramount's major producing properties at December 31, 2001. Paramount's exploration efforts are primarily concentrated in Alberta, British Columbia, the Northwest Territories and California. In past years, the majority of properties were in northeastern Alberta and produced natural gas from shallow, high deliverability natural gas reservoirs whose discovery and development was the focus of the Company's corporate strategy since its inception in 1978. In 2001, production from this traditional area accounted for 48 percent of the Company's total natural gas production. Natural gas production from the Company's core area in Central Alberta accounted for 31 percent of the total production in 2001, with 13 percent from Northwest Alberta, 4 percent from Liard, and the remaining 4 percent from non-operated properties in non-core areas.

Paramount's natural gas liquids production is mainly from operated production at Kaybob, Kaybob North and Pine Creek in Central Alberta. The majority of the Company's crude oil production comes from the Kaybob West property. However, crude oil production also came from the non-operated Hardy, Saskatchewan property which accounted for 6 percent of the Company's total oil and natural gas liquids production.

Paramount's working interests have been determined before royalties and after deduction of any third-party carried interests. Production refers to Paramount's working interest before the deduction of royalties.

NORTHEAST ALBERTA – EAST SIDE – KETTLE

These properties are located in the Company's northeasternmost shallow gas production area. The natural gas produced from these facilities is Cretaceous in age at depths up to 450 metres.

Production from this core area was significantly curtailed with the AEUB decision ordering the shut-in of 77 producing gas wells in which Paramount has a working interest. As a result of this shut-in, the facilities at Chard, Kettle River and Quigley were consolidated into one plant at Kettle River during third quarter 2000 to improve operating efficiencies. The Kettle River property description accounts for the acreage and wells formerly reported separately at Chard and Quigley. Certain of the wells shut-in due to the AEUB decision at Surmont have been recompleted in the Clearwater zone and successfully placed back on production. Thus, gas from this region is currently processed at the Paramount-operated plant at Kettle River, two non-operated plants at Winefred and Surmont where the Company's gas is processed for a custom processing fee, and at a third party-operated plant at Bohn Lake where the Company has a working interest in the facility. Details relative to each major property and facility are described below:

Kettle River
112,960 gross (101,523 net) acres of land assigned reserves
32,960 gross (28,812 net) acres undeveloped lands
112 gross (99.8 net) producing gas wells
44 gross (42.2 net) non-producing wells
Average production to Paramount in 2001: 10.9 MMcf/d

Winefred
67,840 gross (60,928 net) acres of land assigned reserves
29,440 gross (22,720 net) acres undeveloped lands
59 gross (51.7 net) producing gas wells
28 gross (24.5 net) non-producing wells
Average production to Paramount in 2001: 5.5 MMcf/d

Bohn Lake
45,760 gross (14,273 net) acres of land assigned reserves
1,600 gross (533 net) acres undeveloped lands
47 gross (13.3 net) producing gas wells
4 gross (1.3 net) non-producing wells
Average production to Paramount in 2001: 3.4 MMcf/d

NORTHEAST ALBERTA – EAST SIDE – CORNER

These properties, located in the shallow gas region directly west of Kettle River, produce natural gas from the high deliverability Colony, McMurray and Clearwater reservoirs found in this region of the core area.

The Company owns and operates three facilities at Corner, Leismer, and Clyde Lake. Paramount gas is also processed at two third-party-operated facilities at Pony and Thornbury for a custom processing fee. The major producing properties in this area are further detailed below:

Corner
75,520 gross (74,435 net) acres of land assigned reserves
30,720 gross (29,760 net) acres undeveloped lands
60 gross (59.4 net) producing gas wells
20 gross (19.7 net) non-producing wells
Average production to Paramount in 2001: 15.5 MMcf/d

Leismer
112,060 gross (103,074 net) acres of land assigned reserves
97,600 gross (88,489 net) acres undeveloped lands
73 gross (66.8 net) producing gas wells
60 gross (58.5 net) non-producing wells
Average production to Paramount in 2001: 11.2 MMcf/d

Thornbury
48,000 gross (33,984 net) acres of land assigned reserves
3,200 gross (1,152 net) acres undeveloped lands
50 gross (36.2 net) producing gas wells
19 gross (12.8 net) non-producing wells
Average production to Paramount in 2001: 4.9 MMcf/d

Clyde Lake
11,580 gross (10,551 net) acres of land assigned reserves
14,140 gross (14,140 net) acres undeveloped lands
16 gross (15.3 net) producing gas wells
5 gross (5.0 net) non-producing wells
Average production to Paramount in 2001: 3.0 MMcf/d

NORTHEAST ALBERTA – EAST SIDE – COLD LAKE

Cold Lake is located south of the aforementioned properties, still in the northeastern shallow gas region and producing from Cretaceous age clastic reservoirs. Natural gas is processed at two Company-owned plants in this area and at third-party facilities for a custom processing fee. The Company also has a 5 to 6 percent net profit interest in 145 heavy oil wells from two different projects in this area.

Cold Lake
112,906 gross (89,894net) acres of land assigned reserves
45,160 gross (39,448 net) acres undeveloped lands
135 gross (108.6 net) producing gas wells
50 gross (41.0 net) non-producing wells
Average production to Paramount in 2001: 11.9 MMcf/d

NORTHEAST ALBERTA – WEST SIDE

These properties form the Company's Northeast Alberta – West Side core area. This natural gas is produced from carbonate reservoirs of Devonian age at depths ranging from 200 to 600 metres as well as from the Cretaceous age McMurray and Wabiskaw formations.

The Company produces gas from seven facilities in this area, six of which the Company owns and operates; Company-operated facilities include Legend, East Legend, East Liege, North Liege, South Liege and Saleski. The Company owns 50 percent of the third-party-operated plant at Teepee Creek. These properties are described below:

Legend
104,320 gross (87,210 net) acres of land assigned reserves
46,080 gross (45,458 net) acres undeveloped lands
55 gross (44.8 net) producing gas wells
12 gross (9.9 net) non-producing wells
Average production to Paramount in 2001: 17.3 MMcf/d

South Liege
84,640 gross (77,606 net) acres of land assigned reserves
14,080 gross (12,800 net) acres undeveloped lands
26 gross (24.7 net) producing gas wells
46 gross (42.0 net) non-producing wells
Average production to Paramount in 2001: 5.2 MMcf/d

East Legend
10,496 gross (10,496 net) acres of land assigned reserves
10,496 gross (10,496 net) acres undeveloped lands
18 gross (18.0 net) providing gas wells
6 gross (6.0 net) non-producing wells
Average production to Paramount in 2001: 4.7 MMcf/d

Saleski
67,840 gross (61,475 net) acres of land assigned reserves
23,360 gross (20,566 net) acres undeveloped lands
19 gross (18.3 net) producing gas wells
10 gross (9.1 net) non-producing wells
Average production to Paramount in 2001: 4.1 MMcf/d

North Liege
73,280 gross (66,851 net) acres of land assigned reserves
No undeveloped lands
18 gross (17.3 net) producing gas wells
20 gross (17.4 net) non-producing wells
Average production to Paramount in 2001: 3.3 MMcf/d

East Liege
11,840 gross (10,751 net) acres of land assigned reserves
1,920 gross (1,836 net) acres undeveloped lands
10 gross (9.0 net) producing gas wells
4 gross (3.7 net) non-producing wells
Average production to Paramount in 2001: 3.1 MMcf/d

Teepee Creek
77,039 gross (40,121 net) acres of land assigned reserves
70,400 gross (55,680 net) acres undeveloped lands
21 gross (10.5 net) producing gas wells
24 gross (14.0 net) non-producing wells
Average production to Paramount in 2001: 2.7 MMcf/d

CENTRAL ALBERTA

These properties form the Company's core area in Central Alberta and produce natural gas, crude oil and natural gas liquids from the Cretaceous Viking, Spirit River, Notikewin and Bluesky/Gething formations as well as the Triassic Montney formation and the Devonian Swan Hills formation.

Paramount operates natural gas plants at Kaybob North, Kaybob, Clover, Nosehill and Puskwa and an oil battery at Kaybob West. Natural Gas is processed at third-party-operated facilities from Pine Creek, Fox Creek, Kaybob South, Pass Creek and Archean for a processing fee. The Clover plant was commissioned in September 2001. As a twin to the existing plant at 9-34-61-18 W5, both plants are now operated by Paramount. The major producing facilities are described below.

Kaybob North
99,200 gross (87,049 net) acres of land assigned reserves
95,520 gross (79,039 net) acres undeveloped lands
125 gross (98.3 net) producing gas wells
31 gross (22.3 net) non-producing gas wells
25 gross (17.9 net) producing oil wells
20 gross (15.6 net) non-producing oil wells
Average production to Paramount in 2001: 30.7 MMcf/d, 711 Bbl/d

Kaybob
51,680 gross (44,785 net) acres of land assigned reserves
45,440 gross (31,272 net) acres undeveloped lands
55 gross (47.0 net) producing gas wells
21 gross (16.7 net) non-producing gas wells
Average production to Paramount in 2001: 18.8 MMcf/d, 171 Bbl/d

Pine Creek
58,240 gross (21,800 net) acres of land assigned reserves
48,960 gross (39,611 net) acres undeveloped lands
43 gross (25.7 net) producing gas wells
16 gross (9.1 net) non-producing gas wells
4 gross (0.11 net) producing oil wells
Average production to Paramount in 2001: 7.5 MMcf/d, 265 Bbl/d

Clover
11,520 gross (3,076 net) acres of land assigned reserves
2,880 gross (2,560 net) acres undeveloped lands
16 gross (4.7 net) producing gas wells
1 gross (0.1 net) non-producing oil well
Average production to Paramount in 2001: 1.51 MMcf/d*
* Average daily production net to Paramount from the effective acquisition date of September 2001 to year end was 5.2 MMcf/d.

Fox Creek
11,840 gross (5,295 net) acres of land assigned reserves
5,760 gross (5,480 net) acres undeveloped lands
12 gross (6.4 net) producing gas wells
7 gross (3.1 net) non-producing gas wells
1 gross (0.1 net) non-producing oil well
Average production to Paramount in 2001: 2.5 MMcf/d, 21 Bbl/d

Kaybob West
3,840 gross (3,840 net) acres of land assigned reserves
640 gross (640 net) acres undeveloped lands
17 gross (17.0 net) producing oil wells
5 gross (5.0 net) non-producing oil wells
Average production to Paramount in 2001: 1.0 MMcf/d, 576 Bbl/d

NORTHWEST ALBERTA

The Company has four plants in the Northwest Alberta core area at Bistcho Lake, Negus West, Negus East and Assumption. Natural gas is processed through a third-party-operated plant at Pedigree for a processing fee.

The Bistcho Lake plant is located approximately 60 kilometres north of the Zama Lake pipeline terminal. This Company-operated sour gas processing facility produces gas of Middle Devonian age at depths up to 1,500 metres. The plant at Bistcho Lake also processes gas from a third party-operated field to the south at Larne.

The Negus/Assumption area is east of Rainbow Lake. The Negus West, Negus East and Assumption Company-operated plants produce natural gas of Pleistocene age at depths of 30 to 50 metres and/or Cretaceous natural gas from the Bluesky/Gething formations at depths from 250 to 300 metres. The major properties are described below:

Bistcho Lake
60,951 gross (31,026 net) acres of land assigned reserves
356,944 gross (207,474 net) acres undeveloped lands
34 gross (17.9 net) producing gas wells
26 gross (13.8 net) non-producing gas wells
Average production to Paramount in 2001: 9.5 MMcf/d, 21 Bbl/d

Negus East
17,920 gross (14,163 net) acres of land assigned reserves
94,720 gross (91,093 net) acres undeveloped lands
6 gross (5.1 net) producing gas wells
14 gross (9.7 net) non-producing gas wells
Average production to Paramount in 2001: 6.7 MMcf/d

Pedigree
21,120 gross (12,338 net) acres of land assigned reserves
99,336 gross (61,812 net) acres undeveloped lands
17 gross (11.4 net) producing gas wells
16 gross (10.0 net) non-producing gas wells
Average production to Paramount in 2001: 6.1 MMcf/d

Negus West
39,680 gross (30,591 net) acres of land assigned reserves
83,258 gross (44,903 net) acres undeveloped lands
18 gross (18.0 net) producing gas wells
38 gross (26.8 net) non-producing gas wells
Average production to Paramount in 2001: 3.6 MMcf/d

Assumption
6,400 gross (6,400 net) acres of land assigned reserves
32,640 gross (32,640 net) acres undeveloped lands
2 gross (2.0 net) producing gas wells
8 gross (8.0 net) non-producing gas wells
Average production to Paramount in 2001: 2.7 MMcf/d

LIARD BASIN, NORTHEAST BRITISH COLUMBIA / NORTHWEST TERRITORIES

The Company operates two natural gas plants at Tattoo and Maxhamish in northeast British Columbia. Maxhamish produces natural gas of Mississippian age from four wells, three in the Northwest Territories and one in northeast British Columbia. The Tattoo plant, constructed in 2001, produces natural gas of Mississippian age from two wells in northeast British Columbia. Paramount also produces Devonian age natural gas from three wells through a non-operated plant in the Northwest Territories.

Liard/ Maxhamish
15,298 gross (5,766 net) acres of land assigned reserves
487,754 gross (204,233 net) acres undeveloped lands
4 gross (1.8 net) producing gas wells
13 gross (5.9 net) non-producing gas wells
Average production to Paramount in 2001: 5.2 MMcf/d

Liard non-op
14,708 gross (439 net) acres of land assigned reserves
There are no Company interests in undeveloped lands
3 gross (0.2 net) producing gas wells
Average production to Paramount in 2001: 2.5 MMcf/d

Tattoo
1,298 gross (649 net) acres of land assigned reserves
18,818 gross (13,302 net) acres undeveloped lands
2 gross (1.0 net) producing gas wells
1 gross (0.5 net) non-producing gas well
Average production to Paramount in 2001: 1.6 MMcf/d

SELECTED CONSOLIDATED FINANCIAL AND OPERATING INFORMATION

A) ANNUAL FINANCIAL INFORMATION

Year Ended December 31 (thousands of dollars except per share amounts)[1]	2001	2000	1999	1998	1997
Revenues	$ 528,373	$ 391,470	$ 211,658	$ 165,527	$ 130,460
Expenses					
Royalties, net of ARTC	99,706	80,541	37,567	20,874	17,540
Operating	61,045	47,974	39,030	33,005	22,213
Interest	19,291	22,313	15,042	12,745	6,698
General and administrative	12,347	9,660	8,566	4,452	9,405
Lease rentals	4,319	5,231	4,056	4,185	2,498
Current income taxes and other	27,720	2,305	1,567	2,109	1,195
Cash flow from operations	$ 303,938	$ 223,446	$ 105,830	$ 88,157	$ 70,911
Per share – basic	$ 5.11	$ 3.76	$ 1.84	$ 1.62	$ 1.42
Per share – diluted	$ 5.11	$ 3.76	$ 1.84	$ 1.62	$ 1.42
Depreciation and depletion	105,433	50,563	47,013	46,554	33,053
Dry hole costs	8,944	7,019	10,399	11,667	7,378
Net earnings	$ 118,902	$ 86,062	$ 28,683	$ 18,210	$ 23,389
Per share – basic	$ 2.00	$ 1.45	$ 0.50	$ 0.34	$ 0.47
Per share – diluted	$ 2.00	$ 1.45	$ 0.50	$ 0.34	$ 0.47
Balance sheet information					
Capital expenditures (gross)	$ 261,184	$ 249,048	$ 171,079	$ 215,982	$ 184,200
Proceeds of property/equipment sales	$ 11,763	$ 34,205	$ 1,894	$ 19,042	$ 22,600
Working capital (deficiency)	$ 27,674	$ 22,640	$ 16,437	$ (2,346)	$ 2,131
Total assets	$ 1,178,095	$ 1,047,829	$ 740,454	$ 624,195	$ 469,954
Long-term operating bank debt	$ 316,600	$ 315,000	$ 268,819	$ 226,439	$ 139,518
Shareholders' equity	$ 537,156	$ 418,254	$ 328,992	$ 262,932	$ 203,766
Dividends paid	–	–	$ 2,973	$ 2,848	$ 2,460
Per share	–	–	$ 0.05	$ 0.05	$ 0.05
Share information					
Average number of common shares outstanding (thousands)	59,454	59,454	57,529	54,348	49,782
Market price					
High	$ 18.75	$ 20.00	$ 26.00	$ 17.00	$ 17.75
Low	$ 12.00	$ 10.50	$ 12.00	$ 11.00	$ 7.75

B) ANNUAL OPERATING INFORMATION

Year Ended December 31	2001	2000	1999	1998	1997
Reserves (proved and probable)					
Natural gas (Bcf)	564	657	750	788	637
Crude oil and liquids (MBbl)	7,967	5,980	8,880	11,630	13,440
Land holdings (000s acres)					
Gross	6,575	6,216	4,373	4,030	3,555
Net	4,984	4,648	2,834	2,433	2,032
Production					
Natural gas (MMcf/d)	225.0	220.0	220.0	203.5	148.6
Average natural gas price ($/Mcf)	$ 6.12	$ 4.59	$ 2.43	$ 2.02	$ 2.12
Crude oil and liquids (Bbl/d)	2,165	1,571	1,854	1,988	1,392
Average crude oil price ($/Bbl)	$ 35.48	$ 37.80	$ 24.27	$19.22	$ 26.36

Year Ended December 31	2001	2000	1999	1998	1997
Drilling activity (gross)					
Gas wells	167	126	92	111	81
Oil wells	12	11	9	24	28
Standing/service	1	2	3	8	28
Dry and abandoned	16	24	10	29	10
Total	196	163	114	172	147
Success rate (%)	92	85	91	83	93
Number of employees					
Office	108	89	70	63	53
Field	80	68	53	65	46
Total	188	157	123	128	99

(1) All per share amounts are calculated using average number of shares outstanding, except dividends paid per share which are based upon actual shares outstanding at time of dividend declaration.

C) QUARTERLY FINANCIAL INFORMATION

The following information is presented with respect to each of the last eight fiscal quarters:

(thousands of dollars except per share amounts)	2001				2000			
	December 31	September 30	June 30	March 31	December 31	September 30	June 30	March 31
Net revenue	$ 75,232	$ 92,756	$ 114,358	$ 146,321	$ 122,659	$ 75,823	$ 65,712	$ 46,735
Earnings	$ (10,433)	$ 33,249	$ 38,889	$ 57,197	$ 41,857	$ 23,079	$ 14,852	$ 6,274
Per share – basic	$ (0.18)	$ 0.56	$ 0.66	$ 0.96	$ 0.71	$ 0.38	$ 0.25	$ 0.11
Per share – diluted	$ (0.18)	$ 0.56	$ 0.66	$ 0.96	$ 0.71	$ 0.38	$ 0.25	$ 0.11
Cash flow	$ 47,732	$ 66,155	$ 70,654	$ 119,396	$ 97,243	$ 53,271	$ 42,872	$ 30,060
Per share – basic	$ 0.80	$ 1.11	$ 1.19	$ 2.01	$ 1.64	$ 0.89	$ 0.72	$ 0.51
Per share – diluted	$ 0.80	$ 1.11	$ 1.19	$ 2.01	$ 1.64	$ 0.89	$ 0.72	$ 0.51

DIVIDEND POLICY

Paramount has paid a cash dividend in three of the last five fiscal years. Future payments will be dependent upon the financial requirements of the Company to reinvest earnings, the financial condition of the Company and other factors that the Board of Directors of the Company may consider appropriate. The following table summarizes the Company's dividend payment record:

	2001	2000	1999	1998	1997
Per share	$ –	$ –	$ 0.050	$ 0.050	$ 0.050
Dividends paid (thousands of dollars)	$ –	$ –	$ 2,973	$ 2,848	$ 2,460

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A" – SEE PAGES 39 TO 48)

See the Company's Management's Discussion and Analysis relating to the audited financial statements for the fiscal years ended December 31, 2001 and 2000, which form part of this Annual Report.

MARKET FOR SECURITIES

The Common shares of Paramount Resources Ltd. are listed on The Toronto Stock Exchange under the trading symbol 'POU'.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of Paramount Resources Ltd. securities, options to purchase securities, and interests of insiders in material transactions, where applicable, is contained in Paramount's Management Information and Proxy Circular dated March 22, 2002. Additional financial information is contained in the Company's comparative financial statements for the year ended December 31, 2001.

For additional copies of this Annual Report and the materials listed in the preceding paragraphs, please contact:
David J. Broshko, C. A.
Chief Financial Officer

Major Producing Properties

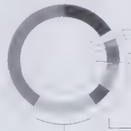
Natural gas (MMcf/d)

	2001	2000	1999	1998	1997
Northeast Alberta East Side					
	3.4				
	2.4				
	3.0				
Cold Lake	11.9	14.4	17.1	13.3	
Corner	15.5	15.1	20.3	25.2	24.1
Kettle River	5.5	10.9	24.9	24.8	23.5
	11.2				
	3.0				
Thornbury	4.9	6.1	6.9	6.8	
Winefred	5.5	6.9	7.1	6.5	
Other	0.8	1.1	4.8	4.8	5.2
	67.1				
Northeast Alberta West Side	17.3				
East Legend	4.7	4.5			
East Edge	3.1	4.2	5.7		
North Edge	3.3	3.8	4.6	6.3	8.3
	5.2				
	4.1				
	2.7				
	1.2				
Subtotal	41.6	42.2	48.4	47.6	33.3
Central Alberta					
	2.5	1.5			
	18.8				
	30.7				
	7.5				
	1.6				
	7.3				
	68.4				
Northwest Alberta					
	2.7	2.8			
Cold Lake	9.5	10.7	10.0	8.0	6.6
Sinclair East	6.7	4.8			
Sinclair West	3.6	1.9			
Sundance	6.1	5.1	3.3		
Other	0.6	0.8	0.7		
	29.2				
Northwest Territories					
	5.2				
	2.5				
	0.6				
Subtotal	9.3	5.4			
Non Core	9.4	5.8	4.8	18.0	24.3
	225.0				
Crude oil & liquids					
	1,855				
	130				
	21				
	59				
	2,065				

Gas Sales & Markets

	2001	
	48	54
ProGas	22	20
	7	
	5	
Selkirk	12	16
California Spot	40	40
	14	
Alberta Spot	77	65
Total Sales	225	220
	37%	
	6%	7%
Spot Market	57%	54%

Net Natural Gas Contracts (2)



Canstates/Temco	1.9
Selkirk	4.5
Waddington Spot	5.0

Undeveloped Land

(thousands of acres)	Gross	Net
Alberta	2,138	1,524
	6	1
Northwest Territories	845	580
Net Land	2001	
	1,218	
Undeveloped	3,765	3,597
	4,984	
	$ 100.9	

Market value is an estimate of the fair market value of acreage based upon current acreage sales

Capital Expenditures

($ millions)	2001	2000
	$ 118.8	
Facilities and equipment	94.8	92.7
Land acquisitions	39.2	24.0
	19.0	
	1.2	
	273.0	-
Property dispositions	(11.8)	(34.2)
	$ 261.2	

Historical Summary

	2001	2000	1999	1998	1997
Gas production (MMcf/d)	225.0	220.0	220.0	203.5	148.6
Crude oil & liquids production (Bbl/d)	2,165	1,571	1,854	1,988	1,392
Gas proved reserves (Bcf)	437.7	518.1	594.7	607.3	481.7
Crude oil & liquids proved reserves (MBbl)	6,339	4,709	5,264	7,895	8,386
Total proved and probable reserves (Bcfe)	643.4	717.2	838.6	904.5	771.2
Cash flow ($MM)	$ 303.9	$ 223.4	$ 105.8	$ 88.1	$ 70.9
Cash flow per share (basic and diluted)	$ 5.11	$ 3.76	$ 1.84	$ 1.62	$ 1.42
Net earnings ($MM)	$ 118.9	$ 86.1	$ 28.7	$ 18.2	$ 23.4
Net earnings per share (basic and diluted)	$ 2.00	$ 1.45	$ 0.50	$ 0.34	$ 0.47

Balance Sheet Information

	2001		
Assets			
Current assets	$ 119.8	$ 145.0	(17)
	1,058.3		
	$ 1,178.1	$ 1,047.8	12
Liabilities and Equity			
	$ 92.1		
Bank loan	316.6	315.0	1
Future site restoration	9.0	6.5	38
	1.4		
	221.9		
Shareholders' equity	537.2	418.3	28
	$ 1,178.1	$ 1,047.8	12

Net Asset Value

Discount rate	10%	15%	20%
Short-term investments	29.6	29.6	29.6
Appraised value of undeveloped acreage	100.0	100.0	100.0
Subtotal	1,089.3	956.3	859.1
Working capital *	13.8	13.8	13.8
Net appraised asset value			
Net appraised asset value per common share			

(2) Based upon Escalating Price Assumptions

(3) Based upon outstanding common shares 59,453,600 at December 31, 2001

Capital Structure

The following table outlines Paramount's capital structure since 1997.

($ thousands)	2001	2000	1999	1998	1997
Bank loan	316,600	315,000	268,819	226,439	139,518
	221,873				
	10,382				
	189,320				
Retained earnings	347,836	228,934	129,672	103,962	88,600
	1,086,011	908,104	688,516	561,832	409,421

Net Debt

	2001	
	$ 119,758	
Less current liabilities	92,084	139,725
Working capital	27,674	5,603
	316,600	315,000
Net debt	$ 288,926	$ 309,397

Estimated Future Net Revenue

	Gas	Oil/liquids	Present value of (millions of dollars)		
Proven	438	6,339	765.2	673.7	604.5
Probable	126	1,628	189.0	148.7	121.4
Total	564	7,967	954.2	822.4	725.9

The discounted net present values of the estimated pre-tax cash flow expected during the economic life of all reserves are based on estimates using escalating price assumptions at rates of 10%, 15% and 20% per annum compounded annually. They are calculated prior to the consideration of income taxes but include ARTC, and are not to be construed as representing the fair market value of properties. The fair market value of the properties and such net present values will depend upon the subjective considerations inherent to each property.

Accounting

- Cash Flow per Share
- Share Price to Cash Flow Multiple
- Debt to Capitalization Ratio
- Debt to Equity Ratio
- Earnings per Share
- [illegible]

common shares outstanding of 59,453,600.

Cash Flow

- net of all lease rentals of both producing and non-producing properties
- [illegible]
- are capitalized
- net of all marketing costs which are currently expensed
- net of all interest expenses, none of which are capitalized

Net Earnings

Paramount further calculates its net earnings:

- net of dry hole costs
- net of geological and geophysical costs

Cash Flow Reconciliation

($ millions)	2001	2000	1999	1998	1997
	528.4				
	99.7				
Net revenue	428.7	310.9	174.1	144.6	112.9
Expenses					
	61.1				
G&A	12.4	9.7	8.6	4.5	
Lease rentals	4.3	5.2	4.1	4.2	
	19.3				
and other	27.7	2.3	1.6	2.1	1.2
Cash flow	303.9	223.4	105.8	88.1	70.9
	71				

(1) Net of ARTC

Cash Flow per Share (1)

1997	70,911	100	49,782	1.42	100
1998	88,157	124	54,348	1.62	114
1999	105,830	149	57,529	1.84	130
2001	303,937	429	59,454	5.11	360

(2) Weighted average shares outstanding

Share Price to Cash Flow Multiple

1997	7.75	11.75	1.42	5.5x	12.5x
1998	11.00	17.00	1.62	6.8x	10.5x
1999	12.00	26.00	1.84	6.5x	14.1x
2001	12.00	18.75	5.11	2.3x	3.7x

Debt to Cash Flow Ratio

year	($ 000s)	($ 000s)	flow ratio	trend
1998	228,785	88,157	2.6:1	137
1999	252,382	105,830	2.4:1	126
2001	288,926	303,937	1.0:1	53

Debt to Equity Ratio

Year				
1998	226,439	561,832	0.40	
1999	268,819	328,992	0.82	
2000	315,000	419,254	0.75	
2001	316,600	537,156	0.59:1	87

Earnings per Share

Paramount's earnings are net of dry hole costs.

Fiscal year	earnings (000s)	Trend	Shares* (000s)	earnings per share ($)	Trend
2001	118,902	508	59,454	2.00	426

(1) Trend with base year 1997 with a nominal value o

Dividend

exception of 198 year since 1985.

2000	-	1.45	-
2001	-	2.00	-

Basic Net Earnings per Shareholders' Share

	2001
	118,902
Weighted ave	
Shareholders	477,705
After-tax rate of return (3)	24.9

OIL & GAS SALES AND GROSS PROFIT

This illustrates oil and gas sales since 1997 and converts the oil sales into gas equivalent (Mcfeq) on an industry standard basis of one barrel of crude oil/liquids equals 10 Mcf of natural gas.

Fiscal year[1]	Oil & gas revenue ($ 000s)	Trend	Gas production (MMcf)	Trend	Oil & liquids production (Bbl)	Trend	Average price Gas ($)	Average price Oil ($)	Gas equivalent production (MMcfeq)	Trend
1997	128,493	100	54,239	100	508,080	100	2.12	26.36	59,320	100
1998	165,527	129	74,278	137	725,620	143	2.03	19.22	81,578	138
1999	211,656	165	80,300	148	676,710	133	2.43	24.27	87,067	147
2000	391,470	305	80,520	148	574,986	113	4.59	37.80	86,270	145
2001	**528,373**	**411**	**82,125**	**151**	**790,225**	**156**	**6.12**	**35.48**	**90,027**	**152**

(1) Trend with base year 1997, with nominal value of 100

OPERATING CASH NETBACKS

Fiscal year[1]	Royalties (net ARTC) ($ 000s)	($/Mcfeq)	Trend	Operating cost ($ 000s)	($/Mcfeq)	Trend	($ 000s)	Operating cash netback[2] ($/Mcfeq)	Trend	% of Revenue
1997	17,540	0.30	100	22,213	0.37	100	89,930	1.52	100	70.0
1998	20,874	0.26	87	33,005	0.40	108	110,077	1.35	89	67.1
1999	37,567	0.43	143	39,030	0.45	122	135,061	1.55	102	63.8
2000	80,561	0.93	310	47,974	0.56	151	262,955	3.05	201	67.2
2001	**99,706**	**1.11**	**370**	**61,045**	**0.68**	**184**	**367,622**	**4.08**	**268**	**69.6**

(1) Trend with base year 1997, with nominal value of 100
(2) Operating Cash Netback = Oil & Gas Revenue – Royalty – Operating Cost

REVENUE/EXPENSES/CASH FLOW NETBACK/NET EARNINGS

The table calculates revenue, expenses and net earnings converted into dollars per thousand cubic feet gas equivalents (1 Barrel equals 10 Mcf).

	2001	2000	1999	1998	1997
Annual Production (MMcfeq)	90,027	86,270	87,067	81,578	59,320
Revenue	$ 5.87	$ 4.54	$ 2.43	$ 2.03	$ 2.20
Net royalties	1.11	0.93	0.43	0.26	0.30
Operating costs	0.68	0.56	0.45	0.40	0.37
Cash netback	4.08	3.05	1.55	1.37	1.53
General and administrative	0.14	0.11	0.10	0.05	0.16
Interest on bank loan	0.21	0.26	0.17	0.16	0.11
Lease rentals and other taxes	0.36	0.09	0.07	0.08	0.06
Cash flow netback	3.37	2.59	1.21	1.08	1.20
Depletion and depreciation	1.20	0.59	0.54	0.58	0.56
Gain on sale of properties	0.02	(0.01)	(0.02)	(0.04)	(0.21)
Dry hole	0.10	0.09	0.12	0.15	0.12
Geological and geophysical	0.12	0.08	0.03	0.06	0.03
Earnings before income taxes	1.93	1.84	0.54	0.33	0.70
Future income taxes	0.62	0.84	0.21	0.11	0.31
Net earnings	$ 1.31	$ 1.00	$ 0.33	$ 0.22	$ 0.39
Net earnings trend[1]	336	256	85	56	100

(1) Trend with base year 1997, with nominal value of 100

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Calgary, Alberta
Canada T2P 5C5
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FAX 403.262.7994
WEB www.paramountres.com

ANNUAL REPORT 2001 ANALYST SUPPLEMENT

This handbook has been prepared by Paramount Resources Ltd. to address the special information needs of the investment community and the sophisticated investor. The handbook provides detailed performance data and key ratios. For additional information please contact:

C.H. (Clay) Riddell, President
D.J. (David) Broshko, Chief Financial Officer
J.H.T. (Jim) Riddell, Corporate Operating Officer
S.L. (Sue) Riddell Rose, Corporate Operating Officer
H.S. (Hugh) Klaassen, Corporate Operating Officer

CORPORATE PROFILE

Paramount Resources Ltd. is a Canadian energy company with 95 percent of its revenue derived from natural gas sales. The Company explores for, develops, produces and markets natural gas, crude oil and natural gas liquids. Paramount has an aggressive, focused exploration and development strategy, concentrated on acquiring land and establishing reserves throughout the Western Canadian Sedimentary Basin.

- 23 years old
- 188 employees (108 head office, 80 field)
- Listed on the Toronto Stock Exchange, symbol 'POU'
- Listed on TSE 200 Index
- 59,454 million shares outstanding
- Market Capitalization: $838 million (December 31, 2001)

Year	Cash flow	Basic per share	Earnings	Basic per share
1999	$ 105.8 million	$ 1.84	$ 28.7 million	$ 0.50
2000	$ 223.4 million	$ 3.76	$ 86.1 million	$ 1.45
2001	**$ 303.9 million**	**$ 5.11**	**$ 118.9 million**	**$ 2.00**

Average number of common shares outstanding for 2001 was 59,453,600

All per share data has been restated to give effect to the 3:1 stock split effective June 4, 1997

UNIQUE TRAITS

- High deliverability, long reserve life shallow gas in northeastern Alberta
- Over 90% of revenue derived from natural gas sales
- "Successful Efforts" accounting policy results in conservative net earnings
- High management ownership (54%)
- Successful full cycle exploration and development creates shareholder value
- Proven performance record through 23 years of commodity price cycles
- Exposure to high impact exploration plays in the Liard Basin and Cameron Hills in the N.W.T., the San Joaquin Basin in California and the Powder River Basin in Wyoming

CONSOLIDATED EARNINGS & CASH FLOW DATA

($ millions except per share amounts)

Year ended December 31	2001	2000	Change (%)
Revenue			
Natural gas	$ 500.0	$ 369.8	35
Crude oil & liquids	28.4	21.7	31
Royalties, net of ARTC	(99.7)	(80.6)	24
Net revenue	428.7	310.9	38
Expenses			
Operating	61.1	48.0	27
Interest	19.3	22.3	(13)
General and administrative	12.4	9.7	28
Dry hole	9.0	7.0	29
Geological and geophysical	10.6	6.8	56
Lease rentals	4.3	5.2	(17)
Site restoration	2.4	1.6	50
Depletion and depreciation	105.4	50.6	108
Other (income) net	1.5	(0.7)	(314)
Current and capital taxes	27.7	2.3	1,104
Future income taxes	56.1	72.0	(22)
Net earnings	$ 118.9	$ 86.1	38
Net earnings per common share – basic	$ 2.00	$ 1.45	38

CASH FLOW RECONCILIATION

Net revenue	$ 428.7	$ 310.9	38
Expenses			
Operating	61.1	48.0	27
Interest	19.3	22.3	(13)
G & A	12.4	9.7	28
Lease rentals	4.3	5.2	(17)
Current and capital taxes	27.7	2.3	1,104
Cash flow	$ 303.9	$ 223.4	36
Cash flow per common share – basic	$ 5.11	$ 3.76	36
Cash flow as a % of net revenue	71%	72%	(2%)

COMPANY FORECAST 2002

Production / Pricing	
Gas (MMcf/d)	250 - 265 @ $ 2.50
Oil/liquids ($MT) (Bbl/d)	2,500 - 3,000 @ $ 29.00
Cash flow ($MM)	$ 185 – $ 200
Cash flow per share	$ 3.10 – $ 3.35
Capital budget ($MM)	$ 175 – $ 200

COMMON SHARE DATA

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol 'POU'. On January 12, 1998 Paramount was added to the TSE 300 Composite Index (Subgroup 3.2 Oil and Gas Producers) and the TSE 200 Index, effective January 16, 1998.

At December 31	2001	2000
Outstanding shares (000s)	59,454	59,454
Public float[1] – shares (000s)	27,432	27,441
– % of total shares	46%	46%
Trading volume (000s)	13,019	18,888
Trading volume as % of public float	47%	69%
Trading value (000s)	$ 195,330	$ 275,953
Trading range		
High	$ 18.75	$ 20.00
Low	$ 12.00	$ 10.50
Close	$ 14.10	$ 17.10
Weighted average trading price	$ 15.00	$ 14.61
Market capitalization at year end ($ millions)	$ 838.3	$ 1,016.7

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors

DIRECTORS AND OFFICERS

C.H. (Clay) Riddell
Director, Chairman & President

D.J. (David) Broshko
Chief Financial Officer

J.H.T. (Jim) Riddell
Director, Corporate Operating Officer

S.L. (Sue) Riddell Rose
Director, Corporate Operating Officer

H.S. (Hugh) Klaassen
Corporate Operating Officer

C.E. (Chuck) Morin
Corporate Secretary

L.A. (Laurel) Friesen
Assistant Corporate Secretary

D. (Dirk) Jungé, C.F.A.
Director

D.M. (David) Knott
Director

W.B. (Wally) MacInnes, Q.C.
Director

G.B. (Barry) Padley, C.A.
Director

V.S.A. (Vi) Riddell
Director

J.B. (John) Roy
Director*

A.S. (Alistair) Thomson
Director

B.M. (Bernie) Wylie
Director

FIVE YEAR SHARE PRICE AND TRADING VOLUME



COMPANY FORECAST 2002

Production / Pricing	
Gas (MMcf/d)	250 – 265 @ $ 2.50
Oil/liquids ($WTI) (Bbl/d)	2,500 – 3,000 @ $ 29.00
Cash flow ($MM)	$ 185 – $ 200
Cash flow per share	$ 3.10 – $ 3.35
Capital budget ($MM)	$ 175 – $ 200

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Public float[1] – shares (000s)	**27,432**	27,441
– % of total shares	**46%**	46%
Trading volume (000s)	**13,019**	18,888
Trading volume as % of public float	**47%**	69%
Trading value (000s)	**$ 195,330**	$ 275,953
Trading range		
High	**$ 18.75**	$ 20.00
Low	**$ 12.00**	$ 10.50
Close	**$ 14.10**	$ 17.10
Weighted average trading price	**$ 15.00**	$ 14.61
Market capitalization at year end ($ millions)	**$ 838.3**	$ 1,016.7

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors

DIRECTORS AND OFFICERS

C.H. (Clay) Riddell
Director, Chairman & President

D.J. (David) Broshko
Chief Financial Officer

J.H.T. (Jim) Riddell
Director, Corporate Operating Officer

S.L. (Sue) Riddell Rose
Director, Corporate Operating Officer

H.S. (Hugh) Klaassen
Corporate Operating Officer

C.E. (Chuck) Morin
Corporate Secretary

L.A. (Laurel) Friesen
Assistant Corporate Secretary

D. (Dirk) Jungé, C.F.A.
Director

D.M. (David) Knott
Director

W.B. (Wally) MacInnes, Q.C.
Director

G.B. (Barry) Padley, C.A.
Director

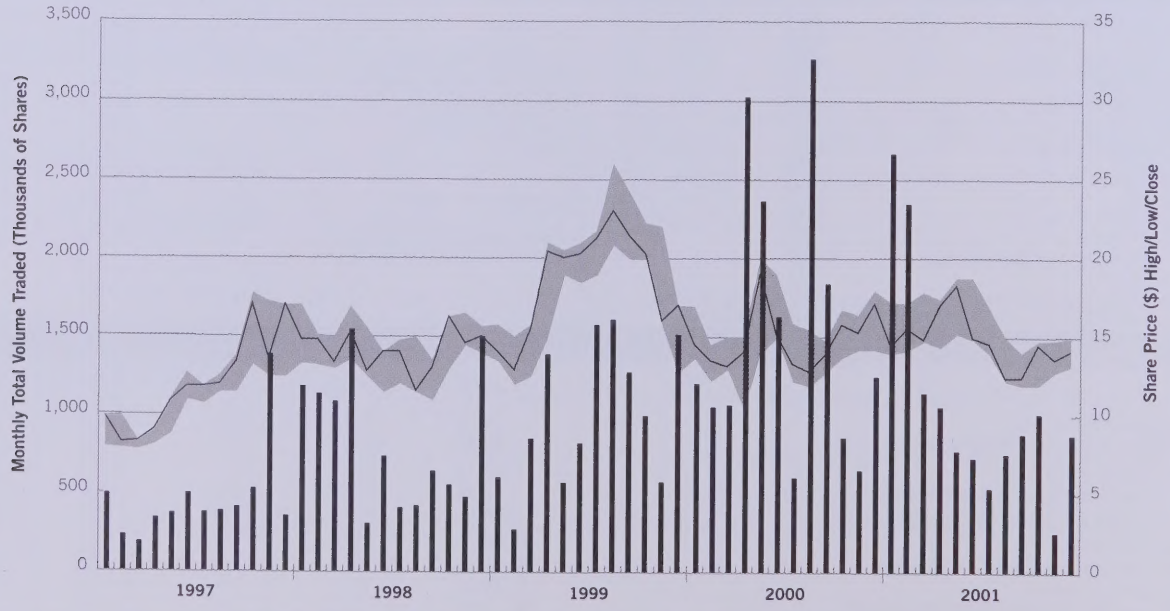
V.S.A. (Vi) Riddell
Director

J.B. (John) Roy
Director

A.S. (Alistair) Thomson
Director

B.M. (Bernie) Wylie
Director

FIVE YEAR SHARE PRICE AND TRADING VOLUME



SHAREHOLDER INFORMATION

OFFICERS

C.H. Riddell
PRESIDENT

D.J. Broshko
CHIEF FINANCIAL OFFICER

S.L. Riddell Rose
CORPORATE OPERATING OFFICER

J.H.T. Riddell
CORPORATE OPERATING OFFICER

H.S. Klaassen
CORPORATE OPERATING OFFICER

C.E. Morin
CORPORATE SECRETARY

L.A. Friesen
ASSISTANT CORPORATE SECRETARY

DIRECTORS

C.H. Riddell [3]
CHAIRMAN OF THE BOARD
PRESIDENT, PARAMOUNT RESOURCES LTD.

D. Jungé, C.F.A.
CHAIRMAN AND CHIEF EXECUTIVE OFFICER
PITCAIRN TRUST COMPANY
JENKINTOWN, PENNSYLVANIA

D.M. Knott
GENERAL PARTNER
KNOTT PARTNERS, L.P.
SYOSSET, NEW YORK

W.B. MacInnes, Q.C. [1][2]
BARRISTER & SOLICITOR
COUNSEL, GOWLING LAFLEUR HENDERSON LLP
CALGARY, ALBERTA

G.B. Padley, C.A.[1]
BUSINESS EXECUTIVE
CALGARY, ALBERTA

J.H.T. Riddell
CORPORATE OPERATING OFFICER
PARAMOUNT RESOURCES LTD.
CALGARY, ALBERTA

S.L. Riddell Rose
CORPORATE OPERATING OFFICER
PARAMOUNT RESOURCES LTD.
CALGARY, ALBERTA

V.S.A. Riddell
BUSINESS EXECUTIVE
CALGARY, ALBERTA

J.B. Roy [1][2][3]
VICE PRESIDENT AND DIRECTOR
INVESTMENT BANKING
JENNINGS CAPITAL INC.
CALGARY, ALBERTA

A.S. Thomson
PRESIDENT
TOUCHE, THOMSON & YEOMAN
INVESTMENT CONSULTANTS LTD.
CALGARY, ALBERTA

B.M. Wylie [2][3]
BUSINESS EXECUTIVE
CALGARY, ALBERTA

(1) Member of Audit Committee
(2) Member of Environmental Committee
(3) Member of Compensation Committee

CONSULTING ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

BANKERS

Bank of Montreal
Main Branch
Calgary, Alberta

SOLICITORS

Gowling Lafleur Henderson LLP
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Canada
Calgary, Alberta
Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
("POU")

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ANNUAL MEETING
Shareholders are cordially invited to attend the Annual Meeting to be held June 20, 2002, at 3:30 pm
Calgary Petroleum Club
McMurray Room
319 Fifth Avenue S.W.
Calgary, Alberta